Applied
PETROLEUM RESERVOIR ENGINEERING

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Gas Reservoirs

1. History of Reservoir Engineering. Crude oil, natural gas, and water are the substances which are of chief concern to petroleum engineers. Although these substances sometimes occur as solids or semisolids, usually at lower temperatures and pressures, as paraffin, gas-hydrates, ices, or high pour-point crudes, in the ground and in the wells they occur mainly as *fluids*, either in the *vapor* (gaseous) or in the *liquid* phase, or, quite commonly both. Even where solid materials are used, as in drilling, cementing, and fracturing, they are handled as fluids or slurries. The division of the well and reservoir fluids between the liquid and vapor phases depends mainly upon the temperature and pressure. The state or phase of a fluid in the reservoir usually changes with pressure, the temperature remaining substantially constant. In many cases the state or phase in the reservoir is quite unrelated to the state of the fluid when it is produced at the surface. The precise knowledge of the behavior of crude oil, natural gas, and water, singly or in combination, under static conditions or in motion in the reservoir rock and in pipes and under changing temperature and pressure, is the main concern of petroleum engineers.

As early as 1928 petroleum engineers were giving serious consideration to gas-energy relationships and recognized the need for more precise information concerning physical conditions as they exist in wells and underground reservoirs. Early progress in oil recovery methods made it obvious that computations made from wellhead or surface data were generally misleading. Sclater and Stephenson*,[1] described the first recording bottom-hole pressure gauge and thief for sampling fluids under pressure in wells. It is interesting to note that this reference defines bottom-hole data as referring to positive measurements of pressure, temperature, gas-oil ratios, and the

*References throughout the text are given at end of each chapter physical and chemical nature of the fluids. The need for accurate bottom-hole pressures was further emphasized when Millikan and Sidwell[2] described the first precision pressure gauge and pointed out the fundamental importance of bottom-hole pressures to petroleum engineers in determining the most efficient methods of recovery and lifting procedures. With this contribution the engineer was able to measure the most important basic information for reservoir performance calculations, *reservoir pressure.*

The study of the properties of the rocks and their relationship to the fluids they contain in both the static and flowing states is called *petrophysics*. Porosity, permeability, fluid saturations and distributions, electrical conductivity of both the rock and the fluids, pore structure, and radioactivity are some of the more important petrophysical properties of rocks. Fancher, Lewis, and Barnes[3] made one of the earliest petrophysical studies of reservoir rocks in 1933, and in 1934 Wycoff, Botset, Muskat, and Reed[4] developed a method for measuring the permeability of reservoir rock samples based on the fluid flow equation discovered by Darcy in 1856. Wycoff and Botset[5] made a significant advance in their studies of the simultaneous flow of oil and water, and of gas and water in unconsolidated sands. This work was later extended to consolidated sands and other rocks, and in 1940 Leverett and Lewis[6] reported research on the three-phase flow of oil, gas, and water.

It was early recognized by the pioneers in reservoir engineering that before the volumes of oil and gas in place could be calculated, the change in the physical properties of bottom-hole samples of the reservoir fluids with pressure would be required. Accordingly in 1935 Schilthuis[7] described a bottom-hole sampler and a method of measuring the physical properties of the samples obtained. These measurements included the pressure-volume-temperature relations, the saturation or bubble-point pressure, the total quantity of gas dissolved in the oil, the quantities of gas liberated under various conditions of temperature and pressure, and the shrinkage of the oil resulting from the release of its dissolved gas from solution. This data made the development of certain useful equations feasible, and it also provided an essential correction to the volumetric equation for calculating oil in place.

The next significant development was the recognition and measurement of connate water saturation,[8,9] which was considered indigenous to the formation and remained to occupy a part of the pore space after oil or gas accumulation. This development further explained the poor oil and gas recoveries in low permeability sands with high connate water saturation, and introduced the concept of water, oil, and gas saturations as percentages of the total pore space. The measurement of water saturation provided another important correction to the volumetric equation by correcting the pore volume to hydrocarbon pore space.

While temperature and geothermal gradients had been of interest to geologists for many years, engineers could not make use of this important data until a precision subsurface recording thermometer was developed. Millikan [10] pointed out the significance of temperature data in applications to reservoir and well studies.

From this basic data Schilthuis[11] was able to derive a useful equation, commonly called the Schilthuis material-balance equation. It is a modification of an earlier equation presented by Coleman, Wilde, and Moore,[12] and is one of the most important tools of reservoir engineers. Basically it is a statement of the conservation of matter, and is a method of accounting for the volumes and quantities of fluids initially present in, produced from, injected into, and remaining in a reservoir at any stage of depletion. In reservoirs under water drive the volume of water which encroaches into the reservoir also enters into the material balance on the fluids. Although Schilthuis[11] proposed a method of calculating water encroachment using the material-balance equation, it remained for Hurst[13] and, later, van Everdingen and Hurst[14] to develop methods for calculating water encroachment independent of the material-balance equation, which applies to aquifers of either limited or infinite extent, in either steady-state or unsteady-state flow.

Following these developments for calculating the quantities of oil and gas initially in place or at any stage of depletion, Tarner[15] and Buckley and Leverett[16] laid the basis for calculating the oil recovery to be expected for particular rock and fluid characteristics. Tarner and, later, Muskat[17] presented methods for calculating recovery by the internal or solution gas drive mechanism, while Buckley and Leverett presented methods for calculating the displacement of oil by external gas cap drive and water drive. These methods not only provided means for estimating recoveries for economic studies, but they also explained the cause for disappointingly low recoveries in many fields. This discovery in turn pointed the way to improved recoveries by taking advantage of the natural forces and energies, and by supplying supplemental energy by gas and water injection, and by unitizing reservoirs to offset the losses which may be caused by competitive operations.

With the development of these techniques, concepts, and equations, reservoir engineering became a powerful and well defined branch of petroleum engineering. Reservoir engineering may be defined as the application of scientific principles to the drainage problems arising during the development and production of oil and gas reservoirs. It has also been defined as "the art of developing and producing oil and gas fields in such a manner as to obtain a high economic recovery."[18] The working tools of the reservoir engineer are subsurface geology, applied mathematics, and the basic laws of physics and chemistry governing the behavior of liquid and vapor phases of crude oil, natural gas, and water in reservoir rocks. Since reservoir engineering is the science of producing oil and gas, it includes a study of all the factors affecting their recovery. Clark and Wessely[19] urge a joint application of geological and engineering data to arrive at sound field development programs. Ultimately reservoir engineering is of concern to all petroleum engineers, from the drilling engineer who is planning the mud program to the corrosion engineer who must design the tubing string for the producing life of the well.

2. Petroleum Reservoirs. Oil and gas accumulations occur in underground *traps* formed by structural and/or stratigraphic features.[20] Fortunately they usually occur in the more porous and permeable portions of beds, which are mainly sands, sandstones, limestones, and dolomites, in the intergranular openings, or in pore spaces due to joints, fractures, and solution activity. A *reservoir* is that portion of a trap which contains oil and/or gas as a single hydraulically-connected system. Many hydrocarbon reservoirs are hydraulically connected to various volumes of water-bearing rock called *aquifers*. Many reservoirs are located in large sedimentary basins and share a common aquifer. In this case the production of fluid from one reservoir will cause the pressure to decline in other reservoirs by fluid communication through the aquifer. In some cases the entire trap is filled with oil or gas, and in this case the trap and the reservoir are the same.

Oil and gas are displaced to the wells by (a) fluid expansion, (b) fluid displacement, natural or artificial, (c) gravitational drainage, and/or (d) capillary expulsion. Where there is no aquifer, and no fluid is injected into the reservoir, the hydrocarbon recovery is brought about mainly by fluid expansion; however, in the case of oil it may be materially aided by gravitational drainage. When there is water influx from the aquifer or where, in lieu of this, water is injected into selected wells, recovery is accomplished by the displacement mechanism, which again may be aided by gravitational drainage or capillary expulsion. Gas is also injected as a displacing fluid to help in the recovery of oil, and is also used in gas cycling to recover gas-condensate fluids. In many reservoirs all four recovery mechanisms may be operating simultaneously, but generally one or two predominate. During the producing life of a reservoir the predominance may shift from one mechanism to another, either naturally or because of operations planned by engineers. For example, a volumetric reservoir (no aquifer) may produce initially by fluid expansion. When its pressure is largely depleted, it may produce to the wells mainly by gravitational drainage, the fluid being lifted to the surface by pumps. Still later, water may be injected in some wells to drive additional oil to other wells. Such a process is commonly called water flooding or secondary recovery. In this case the cycle of the mechanisms is expansion-gravitational drainage-displacement. There are, of course, many alternatives in these cycles, and it is the object of reservoir engineering to plan these cycles for maximum recovery, usually in minimum time.

Under initial reservoir conditions the hydrocarbon fluids are in either a single-phase or a two-phase state. The single phase may be a liquid phase in which all the gas present is dissolved in the oil. There are therefore dissolved gas reserves as well as oil reserves to be estimated. On the other hand the single phase may be a gas phase. If there are hydrocarbons vaporized in this gas phase which are recoverable as liquids on the surface, the reservoir is called gas-condensate, or gas-distillate (the older name). In this case there are associated liquid (condensate or distillate) reserves as well as the gas reserves to be estimated. Where the accumulation is in a two-phase state, the vapor phase is called the gas cap and the underlying liquid phase, the oil zone. In this case there will be four types of reserves to be estimated: the free gas, the dissolved gas, the oil in the oil zone, and the recoverable liquid from the gas cap. Although the hydrocarbons in place are fixed quantities, the *reserves*, that is, the recoverable portion of the in-place gas, condensate, and oil depend upon the method by which the reservoir is produced.

3. Symbols and Conversion Factors. A letter symbol for a physical quantity is a single letter intended for use in mathematical expressions. Special conditions of phase, pressure, time, etc., are indicated by subscripts. Prior to 1953 many publications in the field of reservoir engineering adopted new sets of symbols. This was not only confusing and time consuming to the student, but to all engineers and technical people who were keeping abreast of the many publications. This obstacle was recognized and, after three years of study, in 1956 a standard set of symbols for reservoir engineering was adopted by the Society of Petroleum Engineers of the American Institute of Mining, Metallurgical, and Petroleum Engineers (AIME).[21] These standard symbols are given in Table 1.1 and will be used throughout this text. Although the list may appear formidable at first glance, a closer inspection will show that relatively few letters and subscripts are used, but in many combinations. For example, R stands for gas-liquid ratio. Without any subscript it stands for the current or producing gas-oil ratio; R_s stands for the *solution* gas-oil ratio; R_{si} stands for the *initial* solution gas-oil ratio; R_{sw} stands for the solution gas-water ratio; etc.

Table 1.1. STANDARD LETTER SYMBOLS FOR PETROLEUM RESERVOIR ENGINEERING ADOPTED BY THE SOCIETY OF PETROLEUM ENGINEERS OF AIME

English		Dimensions
A	area	L^2
B	formation volume factor	
B_g	gas formation volume factor	
B_o	oil formation volume factor	
B_t	total (two-phase) formation volume factor	
B_w	water formation volume factor	
c	compressibility	Lt^2/m
c_f	formation (rock) compressibility	Lt^2/m
c_g	gas compressibility	Lt^2/m
c_o	oil compressibility	Lt^2/m
c_w	water compressibility	Lt^2/m
C	concentration	various
D	depth	L
D	diffusion coefficient	L^2/t
e	influx (encroachment) rate	L^3/t
e_g	gas influx (encroachment) rate	L^3/t
e_o	oil influx (encroachment) rate	L^3/t
e_w	water influx (encroachment) rate	L^3/t
f	fraction (such as the fraction of a flow stream consisting of a particular phase)	
g	acceleration of gravity	L/t^2
G	total initial gas in place in reservoir	L^3
G_e	cumulative gas influx (encroachment)	L^3
G_i	cumulative gas injected	L^3
G_p	cumulative gas produced	L^3
ΔG_e	gas influx (encroachment) during an interval	L^3
ΔG_i	gas injected during an interval	L^3
ΔG_p	gas produced during an interval	L^3
h	net pay thickness	L
H	gross pay thickness	L
i	injection rate	L^3/t
i_g	gas injection rate	L^3/t
i_w	water injection rate	L^3/t
I	injectivity index	L^4t/m
I_s	specific injectivity index	L^3t/m
J	productivity index	L^4t/m
J_s	specific productivity index	L^3t/m
k	absolute permeability	L^2
k_g	effective permeability to gas	L^2
k_o	effective permeability to oil	L^2
k_{rg}	relative permeability to gas	

Table 1.1 (CONTINUED).

k_{ro}	relative permeability to oil	
k_{rw}	relative permeability to water	
k_w	effective permeability to water	L^2
K	equilibrium ratio (y/x)	
ln	natural logarithm, base e	
log	common logarithm, base 10	
L	length	L
L	moles of liquid phase	
m	mass	m
m	ratio initial reservoir free gas volume to initial reservoir oil volume	
M	mobility ratio* (λ_1/λ_2)	
M	molecular weight	m
n	total moles	
N	initial oil in place in reservoir	L^3
N_e	cumulative oil influx (encroachment)	L^3
N_p	cumulative oil produced	L^3
ΔN_e	oil influx (encroachment) during an interval	L^3
ΔN_p	oil produced during an interval	L^3
p	pressure	m/Lt^2
p_a	atmospheric pressure	m/Lt^2
p_b	bubble-point (saturation) pressure	m/Lt^2
p_c	critical pressure	m/Lt^2
p_{cf}	casing pressure, flowing	m/Lt^2
p_{cs}	casing pressure, static	m/Lt^2
p_d	dew-point pressure	m/Lt^2
p_D	dimensionless pressure	
p_e	external boundary pressure	m/Lt^2
p_f	front or interface pressure	m/Lt^2
p_i	initial pressure	m/Lt^2
p_r	reduced pressure	
p_{sc}	pressure, standard conditions	m/Lt^2
p_{sp}	separator pressure	m/Lt^2
p_{tf}	tubing pressure, flowing	m/Lt^2
p_{ts}	tubing pressure, static	m/Lt^2
p_w	bottom-hole pressure, general	m/Lt^2
p_{wf}	bottom-hole pressure, flowing	m/Lt^2
p_{ws}	bottom-hole pressure, static	m/Lt^2
$\overline{p}$	average pressure	m/Lt^2
P_c	capillary pressure	m/Lt^2
q	production rate	L^3/t
q_D	dimensionless production rate	
q_g	gas production rate	L^3/t

*When the mobilities involved are on opposite sides of an interface, the mobility ratio will be defined as the ratio of the displacing phase mobility to the displaced phase mobility, or the ratio of the upstream mobility to the downstream mobility.

Table 1.1 (CONTINUED).

q_o	oil production rate	L^3/t
q_w	water production rate	L^3/t
r	radial distance	L
r_D	dimensionless radial distance	
r_e	external boundary radius	L
r_w	well radius	L
R	producing gas-oil ratio	
R	universal gas constant (per mole)	mL^2/t^2T
R_p	cumulative gas-oil ratio	
R_s	solution gas-oil ratio (gas solubility in oil)	
R_{sw}	gas solubility in water	
S	saturation	
S_g	gas saturation	
S_{gc}	critical gas saturation	
S_{gr}	residual gas saturation	
S_o	oil saturation	
S_{or}	residual oil saturation	
S_w	water saturation	
S_{wc}	critical water saturation	
S_{wr}	residual water saturation	
t	time	t
t_D	dimensionless time	
T	temperature	T
T_c	critical temperature	T
T_r	reduced temperature	
T_{sc}	temperature, standard conditions	T
u	volumetric velocity (flow rate per unit area)	L/t
v	specific volume	L^3/m
v	velocity	L/t
V	moles of vapor phase	
V	volume	L^3
V_b	bulk volume	L^3
V_M	volume per mole	L^3
V_p	pore volume	L^3
V_s	solid volume	L^3
W	initial water in place in reservoir	L^3
W_e	cumulative water influx (encroachment)	L^3
W_i	cumulative water injected	L^3
W_p	cumulative water produced	L^3
ΔW_e	water influx (encroachment) during an interval	L^3
ΔW_i	water injected during an interval	L^3
ΔW_p	water produced during an interval	L^3
x	mole fraction of a component in liquid phase	
y	mole fraction of a component in vapor phase	

Table 1.1 (CONTINUED)

z	gas deviation factor (compressibility factor, $z = pV/nRT$)
z	mole fraction of a component in mixture

Greek

β	beta	thermal cubic expansion coefficient	$1/T$
Δ	delta$_{\text{cap.}}$	difference ($\Delta x = x_2 - x_1$ or $x_1 - x_2$)	$[x]$
η	eta	hydraulic diffusivity ($k/\phi c\mu$ or $\lambda/\phi c$)	L^2/t
λ	lambda	mobility (k/μ)	L^3t/m
λ_g	lambda	gas mobility	L^3t/m
λ_o	lambda	oil mobility	L^3t/m
λ_w	lambda	water mobility	L^3t/m
μ	mu	viscosity	m/Lt
μ_g	mu	gas viscosity	m/Lt
μ_o	mu	oil viscosity	m/Lt
μ_w	mu	water viscosity	m/Lt
ν	nu	kinematic viscosity	L^2/t
ρ	rho	density	m/L^3
ρ	rho	resistivity (electrical)	mL^3/tQ^2
ρ_g	rho	gas density	m/L^3
ρ_o	rho	oil density	m/L^3
ρ_w	rho	water density	m/L^3
σ	sigma	surface tension (interfacial tension)	m/t^2
τ	tau	tortuosity	
ϕ	phi	porosity	
Φ	phi$_{\text{cap.}}$	potential	various
Ψ	psi$_{\text{cap.}}$	stream function	various

Subscripts

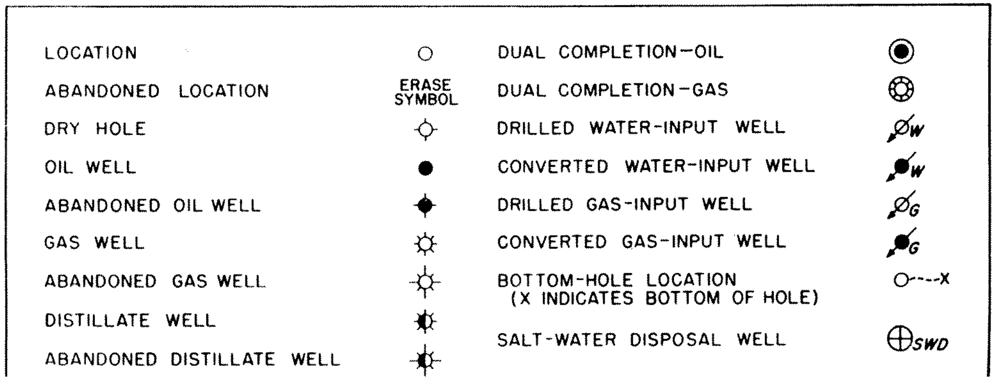
a	atmospheric
b	bubble-point or saturation (except when used with volume)
b	bulk (used with volume only)
c	capillary (used in P_c only)
c	critical
cf	casing, flowing (used with pressure only)
cs	casing, static (used with pressure only)
d	dew-point
d	differential separation
D	dimensionless quantity
e	cumulative influx (encroachment)
e	external boundary conditions
f	flash separation
f	formation (rock)
f	front or interface
g	gas

Table 1.1 (CONTINUED).

i	cumulative injected
i	initial value or conditions
L	liquid
M	molal (used with volume only)
max	maximum
min	minimum
o	oil
p	cumulative produced
p	pore (used with volume only)
r	reduced
r	relative
r	residual
s	gas-oil solution (used in R_s only)
s	solid (used with volume only)
s	specific (used with J and I)
sc	standard conditions
sp	separator conditions
sw	gas-water solution (used in R_{sw} only)
t	total
tf	tubing, flowing (used with pressure only)
ts	tubing, static (used with pressure only)
w	water
w	well conditions
wf	bottom-hole, flowing (used with pressure only)
ws	bottom-hole, static (used with pressure only)

The American Petroleum Institute[22] recognized a similar obstacle in the symbols used in the preparation of subsurface, isopachous, and other field maps, and after due study recommended a set of standard well symbols to promote uniformity in map symbols. Because reservoir engineers frequently use and often prepare or supervise the preparation of oil field maps, the API standard map symbols are given in Table 1.2 for reference.

Table 1.2. API STANDARD SYMBOLS FOR OIL MAPPING



LOCATION	○	DUAL COMPLETION—OIL	◉
ABANDONED LOCATION	ERASE SYMBOL	DUAL COMPLETION—GAS	⊚
DRY HOLE	⌖	DRILLED WATER-INPUT WELL	ØW
OIL WELL	●	CONVERTED WATER-INPUT WELL	●W
ABANDONED OIL WELL	✦	DRILLED GAS-INPUT WELL	ØG
GAS WELL	☼	CONVERTED GAS-INPUT WELL	●G
ABANDONED GAS WELL	☼	BOTTOM-HOLE LOCATION (X INDICATES BOTTOM OF HOLE)	O---X
DISTILLATE WELL	✹	SALT-WATER DISPOSAL WELL	⊕SWD
ABANDONED DISTILLATE WELL	✹		

Table 1.3 presents a set of constants and conversion factors as given by Eilerts.[23] These are the more commonly used constants and conversion factors in reservoir engineering calculations. Whereas most of the constants are given with many significant figures, in many reservoir calculations, owing to the limited number of significant figures in some of the data, the constants may be abbreviated. For example, the absolute temperature corresponding to zero Fahrenheit is usually rounded off to 460°R instead of 459.688°R. The legal base or standard pressures are not included in Table 1.3. In most states it is 14.65 psia, and in Louisiana and New Mexico it is 15.025 psia.

Table 1.3. CONSTANTS AND CONVERSION FACTORS
(*After Eilerts*[23] *and others*)

Basic Constants

Absolute temperature corresponding to 0°F	459.688°R
Maximum density of water (39.16°F)	0.999,973 g per cm³
Density of water at 60°F	0.999,014 g per cm³
Average molecular weight of dry air	28.97
Avogadro's Number	2.733×10^{26} molecules per lb mole

Derived Constants

Gas constant	$10.732 \dfrac{\text{(psi) (cu ft)}}{\text{(lb mole) (deg R)}}$
Volume of 1 lb-mole of gas at 14.4 psia and 60°F	$387.29z^*$ cu ft
Volume of 1 lb-mole of gas at 14.65 psia and 60°F	$380.68z$ cu ft
Volume of 1 lb-mole of gas at 14.696 psia and 60°F	$379.51z$ cu ft
Volume of 1 lb-mole of gas at 14.7 psia and 60°F	$379.41z$ cu ft
Volume of 1 lb-mole of gas at 14.73 psia and 60°F	$378.62z$ cu ft
Density of water at 60°F	62.366 lb per cu ft
One foot of water at 60°F	0.433,10 psi
Weight of water at 60°F	8.337,27 lb per gal

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*z is the gas deviation factor.

Defined Constants

M = 1000 and MM or M² = 1,000,000
MCF = 1000 standard cu ft
Standard legal temperature in most states = 60°F

Units of Length

1 arpent = 191.83 ft
1 cm = 0.393,7 in.
1 ft = 30.480,1 cm
1 ft = 0.3600 varas
1 m = 39.370 in.
1 m = 3.280,8 ft
1 mile = 5280 ft
1 in. = 2.540,01 cm

Units of Area

1 ac = 43,560 sq ft
40 ac = 1320 ft by 1320 ft
1 ac = 208.71 ft sq
1 sq mi = 640 ac

Units of Mass

1 oz = 28.349,53 g
1 lb = 453.592,43 g
1 lb = 16 oz

Table 1.3 (CONTINUED).

Units of Volume

1 ac-ft = 43,560 cu ft
1 ac-ft = 7758.4 bbl
1 bbl = 42 U.S. gal
1 bbl = 5.614,58 cu ft
1 cu ft = 1728 cu in.
1 cu ft = 7.480,5 gal
1 cu ft = 0.178,108 bbl
1 cu m = 6.289,8 bbl
1 gal = 231 cu in.
1 gal = 3785.43 cu cm
1 qt = 946.35 cu cm

Units of Density

1 g per cu cm = 62.428 lb per cu ft
1 g per cu cm = 8.345,5 lb per gal
1 g per cu cm = 350.51 lb per bbl
1 lb per cu ft = 0.016,018,4 g per cu cm

Units of Pressure

1 atm = 760 mm Hg (0°C)
1 atm = 29.921 in. Hg (0°C)
1 atm = 14.696,006 psi
1 atm = 33.899 ft of water (4°C)
1 ft water (4°C) = 0.433,5 psi
1 in. Hg (0°C) = 0.491,2 psi
1 psi = 2.036 in. Hg (0°C)

Temperature Scales

Degrees Fahrenheit (F)	1.8 (degrees C) + 32
Degrees Centigrade (C)	(1/1.8) (degrees F − 32)
Degrees Kelvin (K)	degrees C + 273.16
Degrees Rankine (R)	degrees F + 459.7

4. Atomic and Molecular Weights. Matter in its various forms is composed of atoms. Neglecting the creations of the atomic physicists, there are 92 different kinds of atoms. These comprise the 92 elements of which everything is composed. Compounds are formed by the combination of two or more of these atoms, either of the same kind or of different kinds. Thus two atoms of oxygen will combine to form a molecule of oxygen in air; and a molecule of hydrochloric acid (HCl) is formed by the combination of one hydrogen atom with one chlorine atom. Now oxygen occurs in three forms: (1) atomic oxygen (O); (2) ordinary oxygen (O_2); and ozone (O_3). Suppose we take a bottle fitted with a stopcock and weigh it after complete evacuation, and then weigh it successively filled *under the same conditions of temperature and pressure* with atomic oxygen (O), ordinary oxygen (O_2), and ozone (O_3). We find that the ordinary oxygen (O_2) weighs twice as much as the atomic oxygen, and that the ozone (O_3) weighs three times as much as the atomic oxygen. One important conclusion of this experiment is that equal volumes of different gases under the same conditions of temperature and pressure contain the same number of molecules. The ozone was three times as heavy as the atomic oxygen, not because there were more molecules in the bottle, but because each molecule was three times as heavy as the atomic oxygen molecules (actually atoms); for each contained the same number of molecules. This may appear to be an extremely odd fact; nevertheless it is a fact of great importance.

If we extend the above experiment to weighing the bottle full of hydrogen gas, again at the same temperature and pressure, a weight very close to one eighth ($\frac{1}{8}$) that of the atomic oxygen is observed. For reference purposes the atomic oxygen is assigned an arbitrary relative weight of exactly 16.000, and this relative weight is called its atomic weight. Then the molecular weight of ordinary oxygen is 32.000 and that of ozone 48.000, while hydrogen, whose formula is H_2, has a molecular weight of 2.016 and an atomic weight of 1.008. To illustrate the matter a little further, if the bottle is filled with methane gas, whose formula is CH_4, under the same conditions of temperature and pressure, a weight very close to that of atomic oxygen is observed; for the molecular weight of methane is very close to 16. Since molecular weights are the sum of the atomic weights of the atoms forming the molecule, and since the atomic weight of hydrogen is close to 1.00, then it is inferred that the atomic weight of carbon is very close to 12.00. Further, it may be said that the molecular weight of water is approximately 18, having two hydrogen atoms of an atomic weight of one each, and one oxygen atom of weight 16.

Actually, precise measurements show that the atomic weights of the elements are not exactly whole numbers except for oxygen which has been selected as the starting point of 16.000. Table 1.4 gives a list of the atomic weights of the more common elements encountered by the petroleum engineer. Note that the common gases oxygen, nitrogen, hydrogen, and chlorine exist in their ordinary forms (at atmospheric temperature and pressure) as molecules composed of two atoms.

Table 1.4. ATOMIC AND MOLECULAR WEIGHTS

Element	Symbol	Atomic Weight	Molecular Formula and Weight of Gas	
Argon	A	39.944	A	39.944
Carbon	C	12.010	C	12.010
Chlorine	Cl	35.457	Cl_2	70.914
Helium	He	4.003	He	4.003
Hydrogen	H	1.008	H_2	2.016
Nitrogen	N	14.008	N_2	28.016
Oxygen	O	16.000	O_2	32.000
Sulphur	S	32.066	S	32.066

5. The Mole or Pound Mole. From what has been said it should be clear that under the same conditions of temperature and pressure 2.016 pounds of hydrogen, 32.000 lb of oxygen, 16.04 lb of methane, etc., will all (1) contain the same number of molecules and (2) occupy the same volume. These quantities of gases (or liquids or solids for that matter), equal in pounds to their molecular weights, are called *moles*, or more specifically *pound moles*. A mole of any compound is the number of weight units equal to its molecular weight. For example, a mole of methane is 16.04 weight units of methane. If it is expressed in pounds, then 16.04 lb of methane is a pound mole of methane; if it is expressed in grams, 16.04 g of methane is a gram mole. Obviously, as there are 453.59 g in a pound, a pound mole of methane contains 453.59 times as many molecules as a gram mole of methane. The units of molecular weight then are pounds per pound mole, grams per gram mole, or tons per ton mole.

Now it is has been found by experiment that one mole of any ideal gas under a pressure of 14.7 psia and a temperature of 60°F will occupy a volume of 379.4 cu ft. These conditions of temperature and pressure are called *standard conditions*. There is no one set of standard conditions universally recognized, so it is important to find out what standard conditions form the basis for any calculation or contract.

Now with these concepts in mind it is possible to answer the question: How many pounds of methane are in a 10,000 cubic-foot tank at 14.7 psia and 60°F? The solution is that for every 379.4 cubic feet there is one mole of methane, and every mole of methane weighs 16.04 lb or

$$\frac{10{,}000}{379.4} \times 16.04 = 422.8 \text{ lb of } CH_4 \text{ in the tank}$$

6. The Perfect Gas Law. We were able to calculate above, quite easily, that the 10,000 cubic-foot tank of methane contained 422.8 lb because the gas happened to be at 14.7 psia and 60°F. If the gas had been at other conditions, the problem would have been more difficult because the volume would first have to be converted to the volume it would occupy under the standard conditions. To make the problem more general it can be said that there are three quantities which define the *state* of a gas, i.e., temperature, pressure, and volume. Boyle and Charles in experimenting with these variables found that for any given quantity of gas the following law holds:

$$\frac{p_1V_1}{T_1} = \frac{p_2V_2}{T_2} \tag{1.1}$$

where p_1, V_1, and T_1 are the pressure, volume, and temperature of the gas in *state* 1; and p_2, V_2, and T_2 in *state* 2. In this equation V_1 and V_2 may be measured in any units provided they are the same; p_1 and p_2 may be measured in any units provided they are the same and provided they are *absolute* pressures. T_1 and T_2 may be measured in any units provided they are the same and provided they are *absolute* temperatures.

Now we are in position to answer the following type of question: How many pounds of ethane gas (C_2H_6, molecular weight 30.07) are in a 500 cubic-foot tank under a *gauge* pressure of 20 psig and a temperature of 90°F? Atmospheric pressure is 14.4 psia.

Tank Conditions *Standard Conditions*

$$\frac{p_1 \times V_1}{T_1} = \frac{p_{sc} \times V_{sc}}{T_{sc}}$$

$$\frac{(20 + 14.4) \times 500}{(90 + 459.7)} = \frac{14.7 \times V_{sc}}{(60 + 459.7)}$$

From which V_{sc} = 1106 cu ft, the volume the gas would occupy at standard conditions of 14.7 psia and 60°F. Since there are 379.4 standard cubic feet (SCF) in one mole of gas, and there are 30.07 lb of ethane to the mole, there will be

$$m = \frac{1106 \times 30.07}{379.4} = 87.7 \text{ lb of ethane in the tank}$$

Equation (1.1) is commonly expressed in an alternate form, which can be obtained by recalling that n moles of gas at 60°F and 14.7 psia occupy 379.4 × n cubic feet. Substituting these values in Eq. (1.1),

$$\frac{pV}{T} = \frac{14.7 \times 379.4 \times n}{(60 + 459.7)}$$

$$pV = 10.732\, nT$$

The constant 10.732 is called the *gas constant*, symbol R, and the alternate form of the perfect gas law may be written

$$pV = nRT \tag{1.2}$$

where R will have different values depending on the units of p, V, and T. Where $R = 10.732$, p must be in pounds per square inch absolute, V in cubic feet, and T in degrees Rankine. This form of the perfect gas law is equally suitable for calculating the pounds of ethane in the 500 cubic-foot tank.

$$(20 + 14.4) \times 500 = n \times 10.73 \times (90 + 459.7)$$

$$n = 2.916 \text{ moles}$$

The weight in the tank is

$$m = 2.916 \times 30.07 = 87.7 \text{ lb}$$

From what has been said it follows that a quantity of a pure gas can be expressed as the number of standard cubic feet (SCF) at a specified temperature and pressure, the number of moles, the number of pounds, or the number of molecules. For practical measurement the weighing of gases is difficult, so that gases are metered by volume at measured temperatures and pressures, from which the pounds or moles may be calculated. Example 1.1 illustrates the calculations of the contents of a tank of gas in each of four units.

Example 1.1. Calculating the contents of a tank of ethane in moles, pounds, molecules, and SCF.

Given: A 500 cu ft tank of ethane at 100 psia and 100°F.

SOLUTION: Assuming ideal gas behavior,

$$\text{Moles} = \frac{100 \times 500}{10.732 \times 559.7} = 8.324$$

$$\text{Pounds} = 8.324 \times 30.07 = 250.3$$

$$\text{Molecules} = 8.324 \times 2.733 \times 10^{26} = 22.75 \times 10^{26}$$

At 14.7 psia and 60°F,

$$\text{SCF} = 8.324 \times 379.4 = 3158$$

Alternate solution using Eq. (1.1)

$$\text{SCF} = \frac{100 \times 500 \times 519.7}{559.7 \times 14.7} = 3158$$

Alternate solution using Eq. (1.2)

$$\text{SCF} = \frac{nRT}{p} = \frac{8.324 \times 10.73 \times 519.7}{14.7} = 3158$$

7. Specific Gravity of Gases. Since the density of a substance is defined as mass per unit volume, the density of a perfect gas, ρ_g, at a given temperature and pressure can be derived by substituting m/M for n in the perfect gas law, where m is the pounds of gas and M is the molecular weight.

$$pV = \frac{m}{M} RT$$

$$\rho_g = \frac{m}{V} = \frac{pM}{RT}$$

Because it is more convenient to measure the specific gravity of gases than the gas density, *specific gravity* is more commonly used. *Specific gravity* is defined as the ratio of the density of a gas at a given temperature and pressure to the density of air at the same temperature and pressure, usually near 60°F and atmospheric pressure. Whereas the density of gases varies with temperature and pressure, the specific gravity is independent of temperature and pressure, where the gas obeys the ideal gas law. By the previous equation, the density of air is

$$\rho_{\text{air}} = \frac{p \times 28.97}{RT}$$

Then the specific gravity of a gas is

$$\text{SG} = \frac{\rho_{\text{gas}}}{\rho_{\text{air}}} = \frac{\dfrac{pM}{RT}}{\dfrac{p \times 28.97}{RT}} = \frac{M}{28.97} \qquad (1.3)$$

Equation (1.3) might also have been obtained from the previous statement that 379.4 cu ft of any ideal gas at 14.7 psia and 60°F is one mole, and therefore a weight equal to the molecular weight. Thus, by definition of specific gravity,

$$\text{SG} = \frac{\text{Weight of 379.4 cu ft of gas at 14.7 and 60°F}}{\text{Weight of 379.4 cu ft of air at 14.7 and 60°F}} = \frac{M}{28.97}$$

Thus if the specific gravity of a gas is 0.75, its molecular weight is 21.7 pounds per mole.

8. Nonideal or Real Gases. *All* of what has been said in the previous section applies to a perfect gas. Actually there are no perfect gases; however, many gases near atmospheric temperature and pressure approach ideal behavior. The ideal gas may be defined as one whose pressure will be exactly doubled if its volume is reduced one half, and one whose pressure will be exactly doubled if, keeping the volume constant, the *absolute* temperature is doubled. These are just specific statements of Boyle's and Charles' laws. Now it has been observed in many gases, such as natural gases of interest to petroleum engineers, that if the volume of a gas is compressed to half its former volume, the pressure will be *less than twice* as great, i.e., the gas appears to be more compressible than the ideal gas. The following explanation is given for this behavior. All molecules of real gases have two tendencies: (1) to fly apart from each other because of their constant kinetic motion, and (2) to come together because of electrical attractive forces, which exist between the molecules. At low pressures, since the molecules are quite far apart, the attractive forces are negligible, and the gas behaves close to ideal. Also at high temperatures the kinetic motion, being greater, makes the attractive forces comparatively negligible and, again, the gas approaches ideal behavior.

Since the volume of a gas will be less than half if the pressure is doubled, the gas is said to be supercompressible. The number, which is a measure of the amount the gas deviates from perfect behavior, is sometimes called the *supercompressibility factor*, usually shortened to just the *compressibility factor*. More commonly it is called the *gas deviation factor*, symbol z. This dimensionless quantity varies usually between 0.70 and 1.20, a value of 1.00 representing ideal behavior.

At very high pressures, above about 5000 psia, natural gases pass from a supercompressible condition to one in which compression is more difficult than in the ideal gas. The explanation given for this is that, in addition to the forces mentioned above, when the gas is highly compressed, the volume occupied by the molecules themselves becomes an appreciable portion of the total volume. Since it is really the space between the molecules which is compressed, and there is less compressible space, the gas appears to be more difficult to compress. In addition, as the molecules get closer together, i.e., at high pressure, repulsive forces begin to develop between the molecules. This is indicated by a gas deviation factor greater than unity. The gas deviation factor is by definition the ratio of the volume *actually* occupied by a gas at a given pressure and temperature to the volume it would occupy if it behaved ideally, or

$$z = \frac{V_a}{V_i} = \frac{\text{Actual volume of } n \text{ moles of gas at } T \text{ and } p}{\text{Ideal volume of } n \text{ moles at same } T \text{ and } p} \tag{1.4}$$

The theories above qualitatively explain the behavior of nonideal or real gases. Equation (1.4) may be substituted in the ideal gas law, Eqs. (1.1) and (1.2) to give equations for use with nonideal gases,

$$p\left(\frac{V_a}{z}\right) = nRT \text{ or } pV_a = znRT$$
$$\frac{p_1V_1}{z_1T_1} = \frac{p_2V_2}{z_2T_2} \tag{1.5}$$

where V_a is the actual gas volume, z_1 the gas deviation factor at p_1 and T_1, and z_2 is the gas deviation factor at p_2 and T_2. The gas deviation factor must be determined for every gas and every combination of gases and at the desired temperature and pressure; for it is different for (a) each gas or mixture of gases, (b) each temperature and pressure of that gas or mixture of gases. The omission of the gas deviation factor in gas reservoir calculations may introduce errors as large as 30 per cent.[24] Figure 1.1 shows the gas deviation factors of two gases, one of 0.90 specific gravity and the other of 0.665 specific gravity. These curves show that the gas deviation factors drop from unity at low pressures, to a minimum value near 2500 psia. They rise again to unity near 5000 psia and to values greater than unity at still higher pressures. In the range of 0 to 5000 psia, the deviation factors at the same temperature will be lower for the heavier gas and for the same gas they will be lower at the lower temperature.

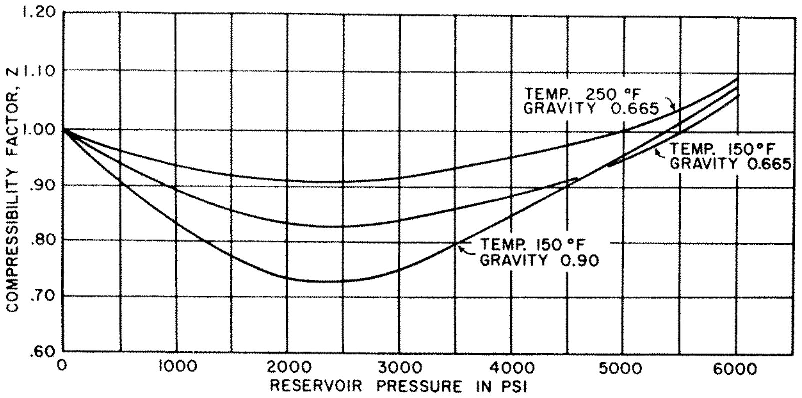

Fig. 1.1. Effect of pressure, temperature, and composition on the gas deviation factor.

The deviation factor of natural gas is commonly measured in the laboratory on samples of surface gases. If there is condensate liquid at the point of sampling, the sample must be taken in such a way as to represent the single-phase reservoir gas. This may be accomplished with a special sampling nozzle or by recombining samples of separator gas, stock tank gas, and stock tank liquid in the proportions in which they are produced. The deviation factor of solution gas is measured on samples evolved from solution in the oil during the liberation process.

The gas deviation factor is commonly determined by measuring the volume of a sample at desired pressures and temperatures, and then measuring the volume of the same quantity of gas at atmospheric pressure, and a temperature sufficiently high so that all of the material remains in the vapor phase. For example, a sample of the Bell Field gas has a measured volume of 364.6 cu cm at 213°F and 3250 psia. At 14.80 psia and 82°F it has a volume of 70,860 cu cm. Then by Eq. (1.5), assuming a gas deviation factor of unity at the lower pressure, the deviation factor at 3250 psia and 213°F is

$$z = \frac{3250 \times 364.6}{460 + 213} \times \frac{1.00 \times (460 + 82)}{14.80 \times 70{,}860} = 0.910$$

If the gas deviation factor is not measured, it may be estimated from its specific gravity. Example 1.2 shows the method for estimating the gas deviation factor from its specific gravity. The correlation charts[25] of Fig. 1.2 are used to estimate the pseudocritical temperature and pressure. Where the carbon dioxide, nitrogen, and hydrogen sulphide content of the gas is known, as from Orsat analysis, the critical values may be corrected for these impurities.[26] The pseudoreduced pressure and temperature are calculated using these critical values. The gas deviation factor is found from the reduced pressure and temperature using the correlation chart[27] of Fig. 1.3. This method gives good results where there is less than 5 per cent impurities and where the gas contains at least 50 per cent methane by volume. As the curves of Fig. 1.2 indicate, the quantity and composition of the condensate content of a natural gas also affect the results, separate curves being given for natural gas with low condensate content and those containing appreciable condensate.

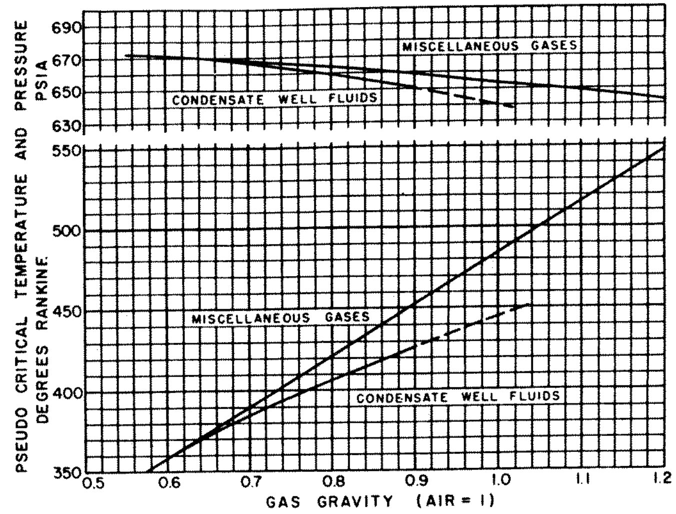

Fig. 1.2. Pseudocritical properties of condensate well fluids and miscellaneous natural gases. (After Brown, Katz, Oberfell, and Alden,[25] courtesy Natural Gasoline Association of America.) **Corrections for impurities.** For each mole per cent of carbon dioxide *subtract* 0.8°R; of hydrogen sulfide *add* 1.3°R; and of nitrogen *subtract* 2.5°R from the pseudocritical temperature. For each mole per cent of carbon dioxide *add* 4.4 psi; of hydrogen sulfide *add* 6.0 psi; and of nitrogen *subtract* 1.7 psi from the pseudocritical pressure. (Corrections after Carr, Kobayashi, and Burrows,[26] *Trans.* AIME.)

Example 1.2. Calculating the gas deviation factor of the Bell Field gas from its specific gravity.

Given:

Specific gravity = 0.665 (air = 1.00)
CO_2 content = 0.10 mole per cent
N_2 content = 2.07 mole per cent
Reservoir temperature = 213°F
Reservoir pressure = 3250 psia

SOLUTION: From Fig. 1.2 the critical pressure and temperature corrected for CO_2 and N_2 are

$$p_c = 669 - 2.07 \times 1.7 + 0.10 \times 4.4 = 666 \text{ psia}$$

$$T_c = 378 - 2.07 \times 2.5 - 0.10 \times 0.8 = 373^\circ\text{R}$$

For 3250 psia and 213°F, the pseudoreduced pressure and temperature are

$$p_r = \frac{3250}{666} = 4.88, \qquad T_r = \frac{460 + 213}{373} = 1.80$$

Enter Fig. 1.3 with these values. Find $z = 0.91$.

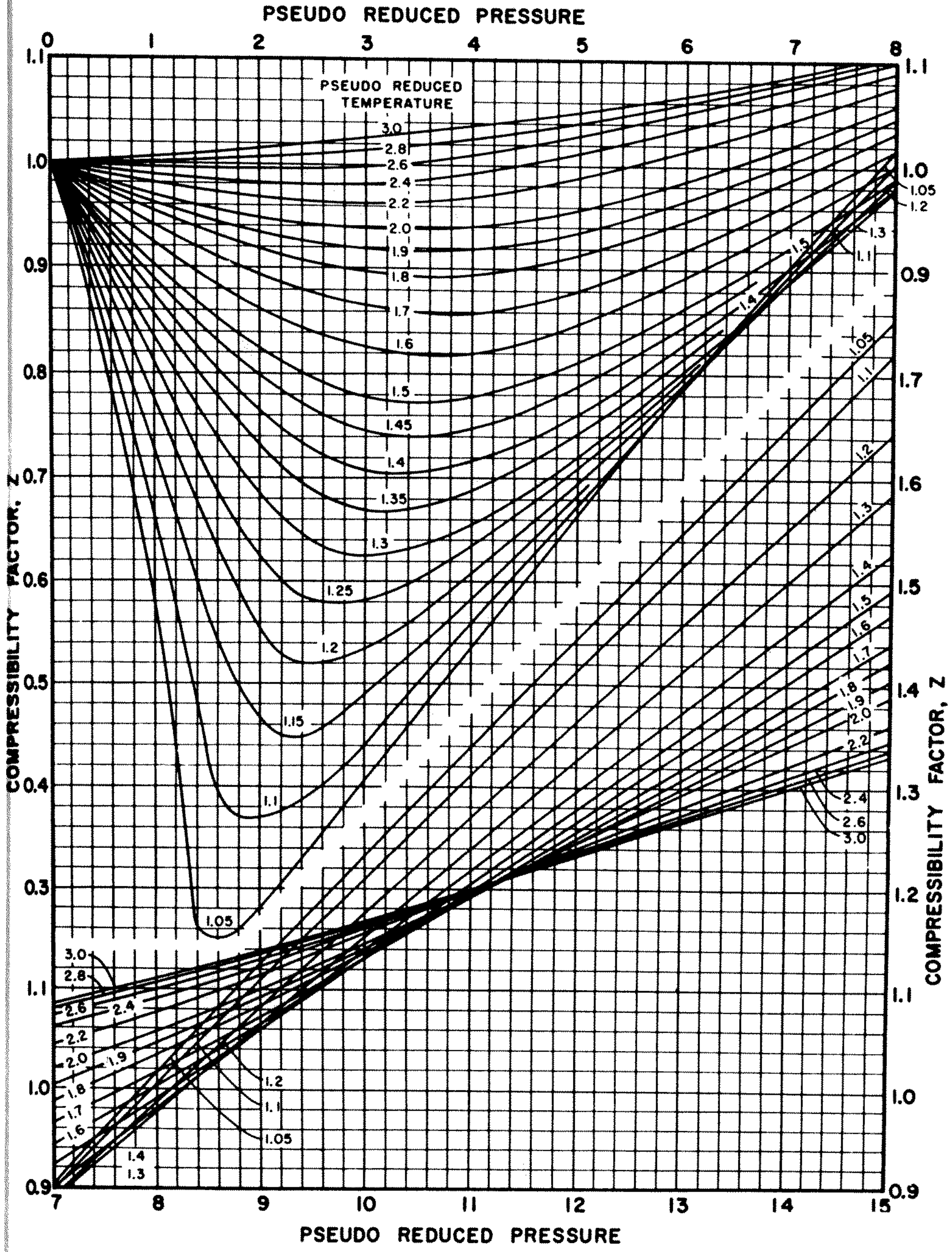

Fig. 1.3. Compressibility factors for natural gases. (After Standing and Katz,[27] *Trans.* AIME.)

A more accurate estimation of the deviation factor can be made where the analysis of the gas is available. This calculation assumes that each component contributes to the pseudocritical pressure and temperature in proportion to its volume per cent in the analysis and to the critical pressure and temperature, respectively, of that component. Table 1.5[23] gives the critical pressures and temperatures of the hydrocarbon compounds and others commonly found in natural gases. It also gives some additional physical properties of these compounds. Example 1.3 shows the method of calculating the gas deviation factor from the composition of the gas.

Example 1.3. Calculating the gas deviation factor of the Bell Field gas from its composition.

Given: The composition Col. (2), and the physical data Cols. (3)–(5) taken from Table 1.5.

(1) Component	(2) Comp., Mole Fract.	(3) Mol. Wt.	(4) p_c	(5) T_c	(6) (2) × (3)	(7) (2) × (4)	(8) (2) × (5)
Methane	0.8612	16.04	673	343	13.81	579.59	295.39
Ethane	0.0591	30.07	708	550	1.78	41.84	32.51
Propane	0.0358	44.09	617	666	1.58	22.08	23.84
Butane	0.0172	58.12	550	766	1.00	9.46	13.18
Pentanes	0.0050	72.15	490	846	0.36	2.45	4.23
CO_2	0.0010	44.01	1070	548	0.04	1.07	0.55
N_2	0.0207	28.02	492	227	0.58	10.18	4.70
	1.0000				19.15	666.67	374.40

SOLUTION: The specific gravity may be obtained from the sum of Col. (6), which is the average molecular weight of the gas,

$$SG = \frac{19.15}{28.97} = 0.661$$

The sums of Cols. (7) and (8) are the pseudocritical pressure and temperature, respectively. Then at 3250 psia and 213°F, the pseudoreduced pressure and temperature are

$$p_r = \frac{3250}{666.67} = 4.87 \qquad T_r = \frac{673}{374.4} = 1.80$$

The gas deviation factor using Fig. 1.3 is $z = 0.91$.

9. Reservoir Gas Volume Factors, Densities, and Gradients. *Gas volume factors*, symbol B_g, relate the volume of gas in the reservoir to the volume on the surface, i.e., at standard conditions, p_{sc} and T_{sc}. They are generally expressed in either cubic feet or barrels of reservoir volume per standard cubic foot of gas, or as the reciprocals of these in standard

Table 1.5. PHYSICAL PROPERTIES OF THE PARAFFIN HYDROCARBONS AND OTHER COMPOUNDS (*After Eilerts*[23])

Compound	Molecular Weight	Boiling Point at 14.7 psia °F	Critical Constants		Liquid Density 60°F, 14.7 psia		Est. Part. Volume at 60°F, 14.7 psia, Gal per M SCF	Est. Part. Volume at 60°F, 14.4 psia, Gal per Lb-mole
			Pressure, p_c, psia	Temperature T_c, °R	G per cc	Lb per Gal		
Methane	16.04	−258.7	673.1	343.2	[a]0.348	2.90	14.6	5.53
Ethane	30.07	−127.5	708.3	549.9	[a]0.485	4.04	19.6	7.44
Propane	44.09	−43.7	617.4	666.0	[b]0.5077	4.233	27.46	10.417
Isobutane	58.12	10.9	529.1	734.6	[b]0.5631	4.695	32.64	12.380
n-Butane	58.12	31.1	550.1	765.7	[b]0.5844	4.872	31.44	11.929
Isopentane	72.15	82.1	483.5	829.6	0.6248	5.209	36.50	13.851
n-Pentane	72.15	96.9	489.8	846.2	0.6312	5.262	36.14	13.710
n-Hexane	86.17	155.7	440.1	914.2	0.6641	5.536	41.03	15.565
n-Heptane	100.2	209.2	395.9	972.4	0.6882	5.738	46.03	17.463
n-Octane	114.2	258.2	362.2	1024.9	0.7068	5.892	51.09	19.385
n-Nonane	128.3	303.4	334	1073	0.7217	6.017	56.19	21.314
n-Decane	142.3	345.4	312	1115	0.7341	6.121	61.27	23.245
Air	28.97	−317.7	547	239				
Carbon dioxide	44.01	−109.3	1070.2	547.5				
Helium	4.003	−452.1	33.2	9.5				
Hydrogen	2.016	−423.0	189.0	59.8				
Hydrogen sulfide	34.08	−76.6	1306.5	672.4				
Nitrogen	28.02	−320.4	492.2	227.0				
Oxygen	32.00	−297.4	736.9	278.6				
Water	18.02	212.0	3209.5	1165.2	0.9990	8.337		

[a] Basis partial volume in solution.

[b] At bubble-point pressure and 60°F.

cubic feet per cubic foot or per barrel of reservoir volume. Assuming a gas deviation factor of unity for the standard conditions, the reservoir volume of one standard cubic foot ($V_{sc} = 1.00$) at reservoir pressure p and temperature T by Eq. (1.5) is

$$B_g = \frac{p_{sc} z T}{T_{sc} p} \tag{1.6}$$

Where p_{sc} is 14.7 psia and T_{sc} is 60°F,

$$\begin{aligned} B_g &= 0.02829 \frac{zT}{p} \text{ cu ft/SCF} \\ &= 0.00504 \frac{zT}{p} \text{ bbl/SCF} \qquad (1.7) \\ &= 35.35 \frac{p}{zT} \text{ SCF/cu ft} \\ &= 198.4 \frac{p}{zT} \text{ SCF/bbl} \end{aligned}$$

The constants in Eqs. (1.7) are *only* for 14.7 psia and 60°F, and different constants must be calculated for other standards. Thus for the Bell Field gas at a reservoir pressure of 3250 psia and a temperature of 213°F and for a gas deviation factor of 0.910, the gas volume factors are

$$\begin{aligned} B_g &= \frac{0.02829 \times 0.910 \times 673}{3250} = 0.00533 \text{ cu ft/SCF} \\ &= \frac{35.35 \times 3250}{0.910 \times 673} = 188 \text{ SCF/cu ft} \end{aligned}$$

These gas volume factors mean that one standard cubic foot (at 14.7 psia and 60°F) will occupy 0.00533 cu ft of space in the reservoir at 3250 psia and 213°F; or expressed reciprocally, one cubic foot of reservoir gas pore space contains 188 SCF. Because oil is usually expressed in barrels and gas in cubic feet, when calculations are made on combination reservoirs containing both gas and oil, either the oil volume must be expressed in cubic feet or the gas volume in barrels. The above gas volume factors expressed in barrels are 0.000949 bbl/SCF and 1054 SCF/bbl, respectively. Then 1000 cu ft of reservoir pore volume in the Bell Field gas reservoir at 3250 psia contains

$$G = 1000 \text{ cu ft} \times 188 \text{ SCF/cu ft} = 188\text{M SCF}$$

Equation (1.5) may also be used to calculate the density of a reservoir gas. The moles of gas in one cubic foot of reservoir gas pore space is p/zRT. By Eq. (1.3) the molecular weight of a gas is 28.97 × SG lb per mole.

Therefore the pounds contained in one cubic foot, that is the *reservoir* gas density, symbol ρ_g, is

$$\rho_g = \frac{28.97 \times \text{SG} \times p}{zRT} \tag{1.8}$$

For example, the density of the Bell Field reservoir gas with a gas gravity of 0.665 is

$$\rho_g = \frac{28.97 \times 0.665 \times 3250}{0.910 \times 10.73 \times 673} = 9.530 \text{ lb/cu ft}$$

The reservoir fluid gradient expressed in pounds per square inch per foot may be obtained by dividing the density in pounds per cubic foot by 144 sq in./sq ft so that Eq. (1.8) becomes

$$\text{Gas gradient} = \frac{0.01875 \times \text{SG} \times p}{zT} \text{ psi/ft} \tag{1.9}$$

In the Bell Field gas reservoir

$$\text{Gas gradient} = \frac{0.01875 \times 0.665 \times 3250}{0.910 \times 673} = 0.0662 \text{ psi/ft}$$

The pressure at the bottom of a shut-in gas well will be greater than the pressure at the surface (wellhead) owing to the weight of the gas contained in the well. Let the pressure at any depth x, measured in feet from the surface, be p in psia. If the cross section of the well bore is A square inches, the pressure at a depth $(x + dx)$ will be $(p + dp)$ owing to the gas contained in the element whose volume is $Adx/144$ cubic feet. The weight of gas dm contained in this element is the product of the gas density ρ_g in pounds per cubic foot and the volume $Adx/144$. Then

$$dp = \frac{dm}{A} = \frac{\rho_g \times A \times dx}{144A} = \frac{\rho_g \, dx}{144}$$

Substituting ρ_g from Eq. (1.8)

$$dp = \frac{28.97 \times \text{SG} \times p \times dx}{144\, zRT}$$

Since 28.97/144R = 0.01875, integrating from the surface to any depth D,

$$\int_{p_{wh}}^{p_{ws}} \frac{dp}{p} = \frac{0.01875 \times \text{SG}}{z_{avg} T_{avg}} \int_0^D dx$$

$$\ln\left(\frac{p_{ws}}{p_{wh}}\right) = \frac{0.01875 \times \text{SG} \times D}{z_{avg} T_{avg}} \tag{1.10}$$

Because the pressure and temperature increase with depth, the gas deviation factor changes. The temperature and the gas deviation factor are removed from the integral signs by assigning average values to them. To a first approximation these values are the arithmetic averages of the top-hole and bottom-hole values. Equation (1.10) may be expressed in exponential form as

$$p_{\mathrm{ws}} = p_{\mathrm{wh}} e^{\frac{0.01875 \times \mathrm{SG} \times D}{z_{\mathrm{avg}} T_{\mathrm{avg}}}} \tag{1.11}$$

For example at 6500 ft in the Bell Field for a wellhead pressure $p_{\mathrm{wh}} = 2759$ psia, using an average temperature of 140°F and an average gas deviation factor of 0.831, the *static* bottom-hole pressure is calculated by Eq. (1.11) to be

$$\begin{aligned} p_{\mathrm{ws}} &= 2759\ e^{\frac{0.01875 \times 0.665 \times 6500}{0.831 \times 600}} \\ &= 3245 \text{ psia} \end{aligned}$$

The substitution of representative values in Eq. (1.11) yields a rule of thumb equation for the increase in pressure of a static gas column as

$$\Delta p = 0.25 \times (p_{\mathrm{wh}}/100) \times (D/100) \tag{1.12}$$

In other words, the pressure in a static gas column increases approximately one fourth of a psi for every hundred psi of wellhead pressure and for every hundred feet of depth. For the Bell Field well the approximate pressure at 6500 ft is

$$p_{\mathrm{ws}} = 2759 + 0.25 \times 27.59 \times 65 = 3207 \text{ psia}$$

Spencer and Boyd[28] have prepared a correlation chart for finding bottom-hole pressures in static gas wells from the surface pressure. Sukkar and Cornell[29] in their work have also included frictional losses, so that *flowing* bottom-hole pressures, as well as static, may be determined for gas wells.

10. Calculating Gas in Place by the Volumetric Method. The standard cubic feet of gas in a reservoir which has a gas pore volume of V_{g} cubic feet is simply $B_{\mathrm{g}} V_{\mathrm{g}}$, where B_{g} is expressed in units of standard cubic feet per cubic foot. As the gas volume factor B_{g} changes with pressure (see Eq. 1.7), the gas in place also changes as the pressure declines. The gas pore volume V_{g} may also be changing, owing to water influx into the reservoir. The gas pore volume is related to the bulk or total reservoir volume by the average porosity ϕ and the average connate water S_{w}. The bulk reservoir volume V_{b} is commonly expressed in acre-feet, and the standard cubic feet of gas in place, G, is given by

$$G = 43{,}560 \times V_{\mathrm{b}} \times \phi \times (1 - S_{\mathrm{w}}) \times B_{\mathrm{g}} \tag{1.13}$$

The areal extent of the Bell Field gas reservoir was 1500 acres. The average thickness was 40 ft, so that the initial bulk volume was 60,000 ac-ft. Average porosity was 22 per cent and average connate water was 23 per cent. B_{g} at the initial reservoir pressure of 3250 psia was previously calculated to be 188 SCF/cu ft. Therefore the initial gas in place was

$$\begin{aligned} G &= 43{,}560 \times 60{,}000 \times 0.22 \times (1 - 0.23) \times 188 \\ &= 83.2\text{MMM SCF} \end{aligned}$$

Since the gas volume factor was calculated using 14.7 psia and 60°F as standard conditions, the initial gas in place is also expressed at these conditions.

The volumetric method makes use of subsurface and isopachous maps based on the data from electric logs, cores, and drill-stem and production tests.[30,31] A *subsurface contour* map is a map showing lines connecting points of equal elevations on the top of a marker bed, and is therefore a map showing geologic structure. A net *isopachous* map is a map showing lines connecting points of equal net formation thickness, and the individual lines connecting points of equal thickness are called *isopach* lines. The reservoir engineer uses these maps to determine the bulk productive volume of the reservoir. The contour map is used in preparing the isopachous maps where there is an oil-water, gas-water, or gas-oil contact. The contact line is the zero isopach line. The volume is obtained by planimetering the areas between the isopach lines of the entire reservoir or of the individual units under consideration. The principal problems in preparing a map of this type are the proper interpretation of net sand thickness from the well logs, and the outlining of the productive area of the field as defined by the fluid contacts, faults, or permeability barriers on the subsurface contour map.

Two equations are commonly used to determine the approximate volume of the productive zone from the planimeter readings. The volume of the frustum of a pyramid is given by

$$\Delta V_{\mathrm{b}} = \frac{h}{3}(A_n + A_{n+1} + \sqrt{A_n A_{n+1}}) \tag{1.14}$$

where ΔV_{b} is the bulk volume in acre-feet, A_n is the area enclosed by the lower isopach line in acres, A_{n+1} is the area enclosed by the upper isopach line in acres, and h is the interval between the isopach lines in feet. This equation is used to determine the volume between successive isopach lines and the total volume is the sum of these separate volumes. The volume of a trapezoid is

$$\Delta V_{\mathrm{b}} = \frac{h}{2}(A_n + A_{n+1})$$

or for a series of successive trapezoids

$$V_{\mathrm{b}} = \frac{h}{2}(A_0 + 2A_1 + 2A_2 \ldots 2A_{n-1} + A_n) + t_{\mathrm{avg}} A_n \tag{1.15}$$

A_0 is the area enclosed by the zero isopach line in acres; $A_1, A_2 \ldots A_n$ are the areas enclosed by successive isopach lines in acres; t_{avg} is the average thickness above the top or maximum thickness isopach line in feet; and h is the isopach interval.

For best accuracy the pyramidal formula should be used; however, because of its simpler form, the trapezoidal formula is commonly used, which introduces an error of 2 per cent when the ratio of successive areas is 0.50. Therefore, a commonly adopted rule in unitization programs is, wherever the ratio of the areas of any two successive isopach lines is smaller than five tenths, the pyramidal formula is applied. Whenever the ratio of the areas of any two successive isopach lines is found to be larger than five tenths, the trapezoidal formula is applied. Example 1.4 shows the method of calculating the volume of a gas reservoir from an isopachous map, Fig. 1.4. The volume between areas A_4 and A_5 by the trapezoidal equation is 570 ac-ft, compared with the more accurate figure of 558 ac-ft by the pyramidal equation. Where the formation is rather uniformly developed and there is good well control, the error in the net bulk reservoir volume should not exceed a few per cent.

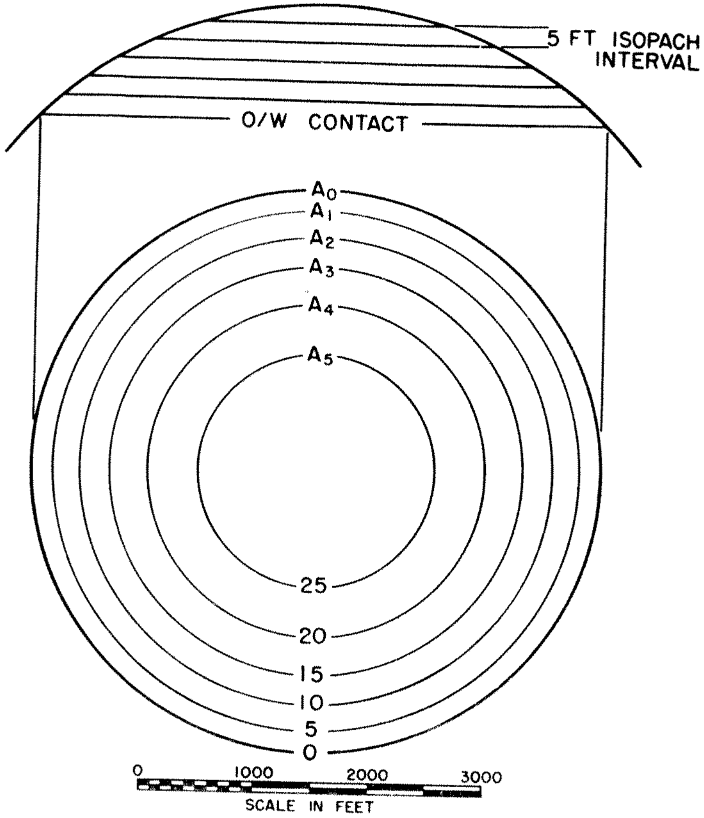

Fig. 1.4. Cross section and isopachous map of an idealized reservoir.

Example 1.4. Calculating the net volume of an idealized reservoir from the isopachous map.

Given: The planimetered areas in Fig. 1.4 within each isopach line, A_0, A_1, A_2, etc. and the planimeter constant.

SOLUTION:

Productive Area	Planimeter Area* sq in.	Area Acres*	Ratio of Areas	Interval h, feet	Equation	ΔV ac-ft
A_0	19.64	450				
A_1	16.34	375	0.83	5	Trap.	2063
A_2	13.19	303	0.80	5	Trap.	1695
A_3	10.05	231	0.76	5	Trap.	1335
A_4	6.69	154	0.67	5	Trap.	963[a]
A_5	3.22	74	0.48	5	Pyr.	558[b]
A_6	0.00	0	0.00	4	Pyr.	99[c]
						6713 ac-ft

*For a map scale of one inch = 1000 ft; one square inch = 22.96 acres.

[a] $\Delta V = \frac{5}{2}(231 + 154) = 963$ ac-ft

[b] $\Delta V = \frac{5}{3}(154 + 74 + \sqrt{154 \times 74}) = 558$ ac-ft

[c] $\Delta V = \frac{4}{3}(74) = 99$ ac-ft

The laboratory methods of measuring porosity include Boyle's law, water-saturation, and organic-liquid saturation methods. Dotson, Slobod, McCreery, and Spurlock[32] have described a porosity-check program made by five laboratories on ten samples. The average deviation of porosity from the average values was ±0.5 porosity per cent. The accuracy of the average porosity of a reservoir as found from core analysis depends upon the quality and quantity of the data available, and upon the uniformity of the reservoir. The average porosity is seldom known more precisely than to one porosity per cent, i.e., to 5 per cent accuracy at 20 per cent porosity. The porosity is also calculated from electric logs and neutron logs, often with the assistance of some core measurements. Logging techniques have the advantage of averaging larger volumes of rock than in core analysis. When calibrated with core data, they should provide average porosity figures in the same range of accuracy as core analysis. Where there are variations in porosity across the reservoir, the average porosity should be found in the same manner as the average reservoir pressure, i.e., on a weighted volume basis.

The water that exists in the oil- and gas-bearing parts of a petroleum reservoir above the transition zone is called *connate* or *interstitial* water. The two terms are used more or less interchangeably. Connate water is important primarily because it reduces the amount of pore space available to oil and gas and it also affects their recovery. It is generally not uniformly distributed throughout the reservoir, but varies with the permeability and lithology as shown in Fig. 1.5, and with the height above the free water table as shown in Fig. 1.6. Schilthuis[9] described the only method for directly measuring the connate water, which consists of coring the producing formation with an oil-base drilling fluid, and he showed that there is a correlation between absolute permeability and connate water. Among the indirect techniques for measuring connate water, one of the first was the capillary pressure method described by Leverett[33] and expanded by Bruce and Welge.[34] McCullough, Albaugh, and Jones[35] developed a technique known as the centrifugal method and Messer[36] developed another known as the evaporation method. Archie[37] showed the quantitative relationship between the resistivity of a formation and its water saturation. Although the relationship depends on lithology and other variables, under favorable conditions the electric log can be used to find connate water within useful limits of accuracy.

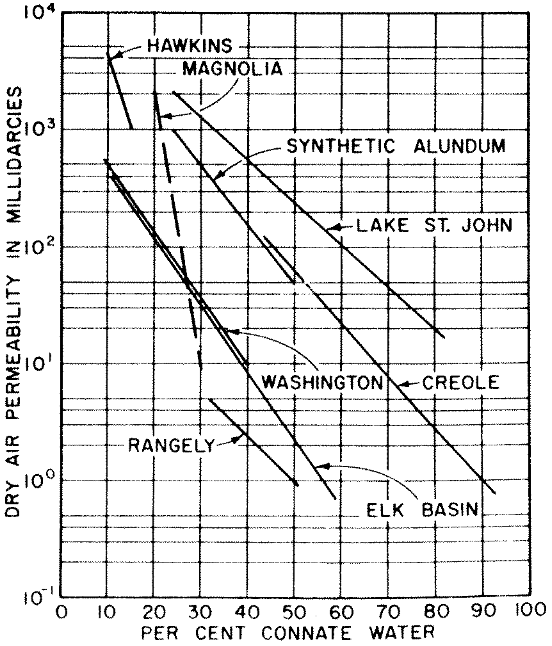

Fig. 1.5. Connate water versus permeability. (Bruce and Welge,[34] *Trans.* AIME.)

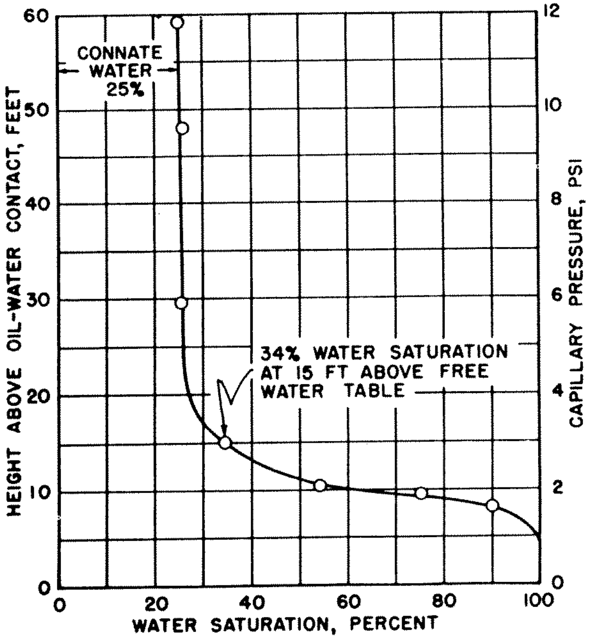

Fig. 1.6. Typical capillary pressure curve.

Another problem in any volumetric or material-balance calculation is that of obtaining the average reservoir pressure at any time after initial production. Figure 1.7 is a static reservoir pressure survey of the Jones

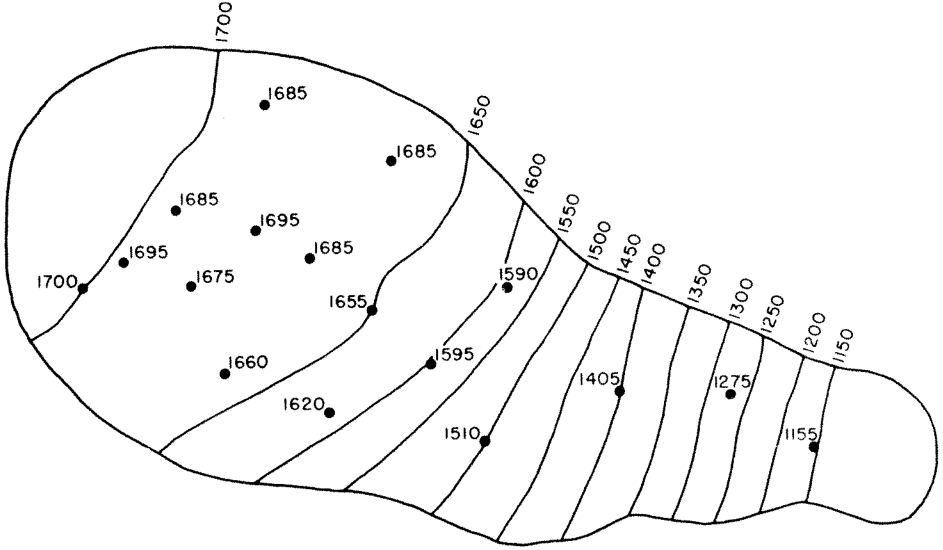

Fig. 1.7. Reservoir pressure survey showing isobaric lines drawn from the measured bottom-hole pressures. (After Kaveler,[38] *Trans.* AIME.)

sand in the Schuler Field.[38] Because of the large reservoir pressure gradient from east to west, some averaging technique must be used to obtain an average reservoir pressure. This can be calculated either as an average well pressure, average areal pressure, or average volumetric pressure as follows:

$$\text{Well average pressure} = \frac{\sum_{0}^{n} p_i}{n} \tag{1.16}$$

$$\text{Areal average pressure} = \frac{\sum_{0}^{n} p_i A_i}{\sum_{0}^{n} A_i} \tag{1.17}$$

$$\text{Volumetric average pressure} = \frac{\sum_{0}^{n} p_i A_i h_i}{\sum_{0}^{n} A_i h_i} \tag{1.18}$$

where n is the number of wells in Eq. (1.16) and the number of reservoir units in Eqs. (1.17) and (1.18). Because we are interested in obtaining the average pressure of the hydrocarbon contents, the volumetric average, Eq. (1.18), should be used in the volumetric and material-balance calculations. Where the pressure gradients in the reservoir are small, the average pressures obtained with Eqs. (1.16) and (1.17) will be very close to the volumetric average. Where the gradients are large there may be considerable differences. For example, the average volumetric pressure of the Jones sand survey in Fig. 1.7 is 1658 psia as compared with 1598 psia on an average well basis.

The calculations in Table 1.6 show how the average pressures are obtained. The figures in Col. (3) are the estimated drainage areas of the wells, which in some cases vary from the well spacing because of the reservoir limits. Owing to the much smaller gradients, the three averages are much closer together than in the case of the Jones sand.

Table 1.6. CALCULATION OF AVERAGE RESERVOIR PRESSURE

Well No.	Pressure psia	Drainage Area Acres	$p \times A$	Est. Sd. Thick.	$p \times A \times h$	$A \times h$
1	2750	160	440,000	20	8,800,000	3200
2	2680	125	335,000	25	8,375,000	3125
3	2840	190	539,600	26	14,029,600	4940
4	2700	145	391,500	31	12,136,500	4495
	10,970	620	1,706,100		43,341,100	15,760

$$\text{Well average pressure} = \frac{10{,}970}{4} = 2743 \text{ psia}$$

$$\text{Areal average pressure} = \frac{1{,}706{,}100}{620} = 2752 \text{ psia}$$

$$\text{Volumetric average pressure} = \frac{43{,}341{,}100}{15{,}760} = 2750 \text{ psia}$$

Most engineers prefer to prepare an isobaric map as illustrated in Fig. 1.8 and to planimeter the areas between the isobaric lines and the isopach lines as shown in Fig. 1.8. Table 1.7, using data taken from Fig. 1.8, illustrates the method of obtaining the average volumetric pressure from this type of map.

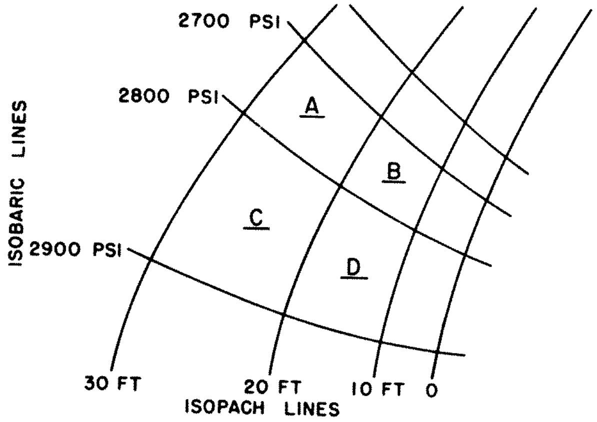

Fig. 1.8. Section of an isobaric and isopachous map.

Table 1.7. VOLUMETRIC CALCULATIONS OF RESERVOIR PRESSURE

(1) Area	(2) Acres*	(3) Pressure psia	(4) h ft	(5) $A \times h$	(6) $p \times A \times h$
A	25.5	2750	25	637.5	175,313,000
B	15.1	2750	15	226.5	62,288,000
C	50.5	2850	25	1262.5	359,813,000
D	30.2	2850	15	453.0	129,105,000
				2579.5	726,519,000

* Planimetered areas of Fig. 1.8

$$\text{Average pressure on a volume basis} = \frac{726{,}519{,}000}{2579.5} = 2817 \text{ psia}$$

11. Calculation of Unit Recovery from Volumetric Gas Reservoirs. In many gas reservoirs, particularly during the development period, the bulk volume is not known. In this case it is better to place the reservoir calculations on a unit basis, usually one acre-foot of bulk reservoir rock.

Then one unit or one acre-foot of bulk reservoir rock contains

Connate water: $43{,}560 \times \phi \times S_w$ cubic feet

Reservoir gas volume: $43{,}560 \times \phi \, (1 - S_w)$ cubic feet

Reservoir pore volume: $43{,}560 \times \phi$ cubic feet

The initial standard cubic feet of gas in place in the unit is

$$G = 43{,}560 \times \phi \times (1 - S_w) \times B_{gi} \text{ SCF/ac-ft} \tag{1.19}$$

G is in standard cubic feet where the gas volume factor B_{gi} is in standard cubic feet per cubic foot, SCF/cu ft, Eq. (1.7). The *standard* conditions are those used in the calculation of the gas volume factor, and they may be changed to any other standard by means of the ideal gas law. The porosity ϕ is expressed as a fraction of the bulk volume, and the connate water S_w as a fraction of the pore volume. For a reservoir under volumetric control there is no change in the interstitial water, so the *reservoir* gas volume remains the same. If B_{ga} is the gas volume factor at the abandonment pressure, then the standard cubic feet of gas remaining at abandonment is

$$G_a = 43{,}560 \times \phi \times (1 - S_w) \times B_{ga} \text{ SCF/ac-ft} \tag{1.20}$$

Unit *recovery* is the difference between the initial gas in place and that remaining at abandonment pressure, i.e., that produced at abandonment pressure, or

$$\text{Unit recovery} = 43{,}560 \times \phi \times (1 - S_w) \times (B_{gi} - B_{ga}) \text{ SCF/ac-ft} \tag{1.21}$$

The unit recovery is also called the *initial unit reserve,* which is generally lower than the initial unit in-place gas. The remaining reserve at any stage of depletion is the difference between this initial reserve and the unit production at that stage of depletion. The fractional recovery or recovery factor expressed in per cent of the initial in-place gas is

$$\text{Recovery factor} = \frac{100(G - G_a)}{G} = \frac{100(B_{gi} - B_{ga})}{B_{gi}} \text{ per cent} \tag{1.22}$$

Experience with volumetric gas reservoirs indicates that the recoveries will range from 80 to 90 per cent. Some gas pipeline companies use an abandonment pressure of 100 psi per 1000 ft of depth.

The gas volume factor in the Bell Gas Field at initial reservoir pressure is 188.0 SCF/cu ft and at 500 psia it is 27.6 SCF/cu ft. The initial unit reserve or unit recovery based on volumetric performance at an abandonment pressure of 500 psia is

$$\begin{aligned}\text{Unit recovery} &= 43{,}560 \times 0.22 \times (1 - 0.23) \times (188.0 - 27.6)\\ &= 1180\text{M SCF/ac-ft}\end{aligned}$$

$$\begin{aligned}\text{Recovery factor} &= \frac{100 \times (188.0 - 27.6)}{188.0}\\ &= 85 \text{ per cent}\end{aligned}$$

These recovery calculations are valid provided the unit neither drains nor is drained by adjacent units.

12. Calculation of Unit Recovery from Gas Reservoirs under Water Drive. Under initial conditions one unit (1 acre-foot) of bulk reservoir rock contains

Connate water: $43{,}560 \times \phi \times S_{wi}$ cubic feet

Reservoir gas volume: $43{,}560 \times \phi \times (1 - S_{wi})$ cubic feet

Surface units of gas: $43{,}560 \times \phi \times (1 - S_{wi}) \times B_{gi}$ standard cubic feet

In many reservoirs under water drive the pressure suffers an initial decline, after which water enters the reservoir at a rate to equal the production, and the pressure stabilizes. In this case the stabilized pressure is the abandonment pressure. If B_{ga} is the gas volume factor at the abandonment pressure and S_{gr} is the *residual* gas saturation, expressed as a fraction of the pore volume, after water invades the unit, then under abandonment conditions a unit (1 acre-foot) of the reservoir rock contains

Water volume: $43{,}560 \times \phi \times (1 - S_{gr})$ cubic feet

Reservoir gas volume: $43{,}560 \times \phi \times S_{gr}$ cubic feet

Surface units of gas: $43{,}560 \times \phi \times S_{gr} \times B_{ga}$ standard cubic feet

Unit recovery is the difference between the initial and the residual surface units of gas, or

$$\text{Unit recovery in SCF/ac-ft} = 43{,}560 \times \phi \times [(1 - S_{wi})B_{gi} - S_{gr}B_{ga}] \tag{1.23}$$

The recovery factor expressed in per cent of the initial gas in place is

$$\text{Recovery factor} = \frac{100[(1 - S_{wi})B_{gi} - S_{gr}B_{ga}]}{(1 - S_{wi})B_{gi}} \text{ per cent} \tag{1.24}$$

Suppose the Bell Gas Field is produced under a water drive such that the pressure stabilizes at 1500 psia. If the residual gas saturation is 24 per cent and the gas volume factor at 1500 psia is 89.1 SCF/cu ft, then the initial unit *reserve* or unit recovery is

$$\begin{aligned}\text{Unit recovery} &= 43{,}560 \times 0.22 \times [(1 - 0.23)188 - (0.24 \times 89.1)]\\ &= 1182\text{M SCF/ac-ft}\end{aligned}$$

The recovery factor under these conditions is

$$\text{Recovery factor} = \frac{100[(1 - 0.23)188 - (0.24 \times 89.1)]}{(1 - 0.23)188}$$
$$= 85 \text{ per cent}$$

Under these particular conditions the recovery by water drive is the same as the recovery by volumetric depletion, illustrated in Sec. 11. If the water drive is very active so that there is essentially no decline in reservoir pressure, unit recovery and the recovery factor become

$$\text{Unit recovery} = 43{,}560 \times \phi \times (1 - S_{wi} - S_{gr}) \times B_{gi} \text{ SCF/ac-ft} \quad (1.25)$$

$$\text{Recovery factor} = \frac{100(1 - S_{wi} - S_{gr})}{(1 - S_{wi})} \text{ per cent} \quad (1.26)$$

For the Bell Gas Field, assuming a residual gas saturation of 24 per cent,

$$\text{Unit recovery} = 43{,}560 \times 0.22 \times (1 - 0.23 - 0.24) \times 188$$
$$= 955\text{M SCF/ac-ft}$$

$$\text{Recovery factor} = \frac{100(1 - 0.23 - 0.24)}{(1 - 0.23)}$$
$$= 69 \text{ per cent}$$

Since the residual gas saturation is independent of the pressure, the recovery will be greater for the lower stabilization pressure.

The residual gas saturation can be measured in the laboratory on representative core samples. Table 1.8 gives the residual gas saturations[39] which were measured on core samples from a number of producing horizons and on some synthetic laboratory samples. The values, which range from 16 to 50 per cent, and average near 30 per cent, help to explain the disappointing recoveries obtained in some water-drive reservoirs. For example, a gas reservoir with an initial water saturation of 30 per cent and a residual gas saturation of 35 per cent has a recovery factor of only 50 per cent if produced under an active water drive, i.e., where the reservoir pressure stabilizes near the initial pressure. Where the reservoir permeability is uniform, this recovery factor should be representative, except for a correction to allow for the efficiency of the drainage pattern and water coning or cusping (see Fig. 5.15 A and B). Where there are well defined continuous beds of higher and lower permeability, the water will advance more rapidly through the more permeable beds so that when a gas well is abandoned owing to excessive water production, considerable unrecovered gas remains in the less permeable beds (see Fig. 5.15 C). The reduction in recovery factor under these conditions is discussed in Chapter 7, Sec. 7. Because of these factors it may be concluded that generally gas recoveries by water drive are lower than by volumetric depletion; however, the same conclusion does not apply to oil recovery, which will be discussed separately. Water-drive gas reservoirs do have the advantage of maintaining higher flowing wellhead pressures and higher well rates compared with depletion gas reservoirs. This is due, of course, to the maintenance of higher reservoir pressure as a result of the water influx.

Table 1.8. RESIDUAL GAS SATURATION AFTER WATER FLOOD AS MEASURED ON CORE PLUGS
(*After Geffen, Parish, Haynes, and Morse*[39])

Porous Material	Formation	Residual Gas Saturation, Per Cent of Pore Space	Remarks
Unconsolidated sand	. . . .	16	(13-ft Column)
Slightly consolidated sand (synthetic)	. . . .	21	(1 Core)
Synthetic consolidated materials	Selas Porcelain	17	(1 Core)
	Norton Alundum	24	(1 Core)
Consolidated sandstones	Wilcox	25	(3 Cores)
	Frio	30	(1 Core)
	Nellie Bly	30–36	(12 Cores)
	Frontier	31–34	(3 Cores)
	Springer	33	(3 Cores)
	Frio	30–38	(14 Cores)
			(Average 34.6)
	Torpedo	34–37	(6 Cores)
	Tensleep	40–50	(4 Cores)
Limestone	Canyon Reef	50	(2 Cores)

In calculating the gas reserve of a particular lease or unit, the gas that can be recovered by the well(s) on the lease is important rather than the total recoverable gas *initially* underlying the lease, some of which may be recovered by adjacent wells. In volumetric reservoirs where the recoverable gas beneath each lease (well) is the same, the recoveries will be the same only if all wells are produced at the same rate. On the other hand if wells are produced at equal rates where the gas beneath the leases (wells) varies, as from variable formation thickness, the initial gas reserve of the lease where the formation is thicker will be less than the initial recoverable gas underlying the lease.

In water-drive gas reservoirs, where the pressure stabilizes near the initial reservoir pressure, the lowest well on structure will divide its initial recoverable gas with all updip wells in line with it. For example, if three wells in line along the dip are drilled at the updip edge of their units, which are presumed equal, and if they all produce at the same rate, the lowest well on structure will recover approximately one third of the gas initially underlying it. If the well is drilled further downstructure near the center of the unit, it will recover still less. If the pressure stabilizes at some pressure below the initial reservoir pressure, the recovery factor will be improved for the wells low on structure. Example 1.5 shows the calculation of the initial gas reserve of a 160-acre unit by volumetric depletion, partial water drive, and complete water drive.

Example 1.5. Calculating the initial gas reserve of a 160-acre unit of the Bell Gas Field by volumetric depletion and under partial and complete water drive.

Given:

Average porosity = 22 per cent

Connate water = 23 per cent

Residual gas saturation after water displacement = 34 per cent

$B_{gi} = 188.0$ SCF/cu ft at $p_i = 3250$ psia

$B_g = 150.0$ SCF/cu ft at 2500 psia
$= 27.6$ SCF/cu ft at 500 psia

Area = 160 acres

Net productive thickness = 40 ft

SOLUTION:

Pore Volume $= 43{,}560 \times 0.22 \times 160 \times 40 = 61.33 \times 10^6$ cu ft

Initial gas in place:

$$G_1 = 61.33 \times 10^6 \times (1 - 0.23) \times 188.0 = 8878\text{MM SCF}$$

Gas in place after volumetric depletion to 2500 psia:

$$G_2 = 61.33 \times 10^6 \times (1 - 0.23) \times 150 = 7084\text{MM SCF}$$

Gas in place after volumetric depletion to 500 psia:

$$G_3 = 61.33 \times 10^6 \times (1 - 0.23) \times 27.6 = 1303\text{MM SCF}$$

Gas in place after water invasion at 3250 psia:

$$G_4 = 61.33 \times 10^6 \times 0.34 \times 188.0 = 3920\text{MM SCF}$$

Gas in place after water invasion at 2500 psia:

$$G_5 = 61.33 \times 10^6 \times 0.34 \times 150 = 3128\text{MM SCF}$$

Initial reserve by depletion to 500 psia:

$$G_1 - G_3 = (8878 - 1303) \times 10^6 = 7575\text{MM SCF}$$

Initial reserve by water drive at 3250 psia:

$$G_1 - G_4 = (8878 - 3920) \times 10^6 = 4958\text{MM SCF}$$

Initial reserve by water drive at 2500 psia:

$$(G_1 - G_2) + (G_2 - G_5) = (G_1 - G_5) = (8878 - 3128) \times 10^6 = 5750\text{MM SCF}$$

If there is one updip well, the initial reserve by water drive at 3250 psia is

$$\tfrac{1}{2}(G_1 - G_4) = \tfrac{1}{2}(8878 - 3920) \times 10^6 = 2479\text{MM SCF}$$

13. Material Balances in Gas Reservoirs. In the previous sections the initial gas in place was calculated on a unit basis of one acre-foot of bulk productive rock from a knowledge of the porosity and connate water. To calculate the initial gas in place on any particular portion of a reservoir it was necessary to know, in addition, the bulk volume of that portion of the reservoir. In many cases the porosity, connate water, and/or the bulk volumes are not known with any reasonable precision, and the methods described can not be used. In this case the *material-balance* method may be used to calculate the initial gas in place; however, this method is applicable only to the reservoir as a whole, because of the migration of gas from one portion of the reservoir to another in both volumetric and water-drive reservoirs.

The conservation of mass may be applied to gas reservoirs to give the following material balance:

$$\begin{bmatrix}\text{Weight of gas}\\ \text{produced}\end{bmatrix} = \begin{bmatrix}\text{Weight initially}\\ \text{in the reservoir}\end{bmatrix} - \begin{bmatrix}\text{Weight remaining}\\ \text{in the reservoir}\end{bmatrix}$$

The balance may also be made on any definable component, e.g., methane. Where the composition of the production is constant, the standard cubic feet both produced and remaining in the reservoir are directly proportional to the masses, and a material balance may be made in terms of standard cubic feet, as

$$\begin{bmatrix}\text{SCF produced}\\ \text{from the reservoir}\end{bmatrix} = \begin{bmatrix}\text{SCF initially}\\ \text{in the reservoir}\end{bmatrix} - \begin{bmatrix}\text{SCF remaining}\\ \text{in the reservoir}\end{bmatrix}$$

Finally, a material balance may be made in terms of moles of gas, as

$$n_p = n_i - n_f \tag{1.27}$$

The subscripts p, i, and f stand for produced, initial, and final, respectively. The term final means at some later stage of production rather than necessarily at abandonment. If V_i is the initial *gas* pore volume in cubic feet, and if at the final pressure p_f, W_e cubic feet of water has encroached into the reservoir and W_p cubic feet of water has been produced from the reservoir, then the final volume V_f after producing G_p standard cubic feet of gas is

$$V_f = V_i - W_e + B_wW_p \tag{1.28}$$

B_w is the volume factor for the water in units of barrels per surface barrel. V_i and V_f are gas pore volumes, i.e., they do not include connate water. The terms in Eq. (1.27) may be replaced by their equivalents using the gas law, Eq. (1.5), and Eq. (1.28), as

$$\frac{p_{sc}G_p}{T_{sc}} = \frac{p_iV_i}{z_iT} - \frac{p_f(V_i - W_e + B_wW_p)}{z_fT} \tag{1.29}$$

G_p is the standard cubic feet of produced gas at standard pressure and temperature, p_{sc} and T_{sc}.

For volumetric reservoirs there is no water influx and water production is generally negligible, and Eq. (1.29) reduces to

$$\frac{p_{sc}G_p}{T_{sc}} = \frac{p_iV_i}{z_iT} - \frac{p_fV_i}{z_fT} \tag{1.30}$$

For fixed values of p_{sc} and T_{sc}, since p_i, z_i, and V_i are also fixed for a given volumetric reservoir, Eq. (1.30) may be written as

$$G_p = b - m\left(\frac{p_f}{z_f}\right) \tag{1.31}$$

where $$b = \frac{p_iV_iT_{sc}}{z_ip_{sc}T} \text{ and } m = \frac{V_iT_{sc}}{p_{sc}T}$$

Equation (1.31) indicates that for a *volumetric* gas reservoir the graph of the cumulative gas production G_p in standard cubic feet versus the ratio p/z is a straight line of negative slope m. Figure 1.9 shows a plot of cumulative gas production in standard cubic feet plotted versus p/z. Within the limits of error of the values of average reservoir pressure and cumulative productions, the plot of G_p versus p/z is linear and may be extrapolated to zero pressure to find the initial gas in place, or to any abandonment value of p/z to find the initial reserve. The slope m in Fig. 1.9 is

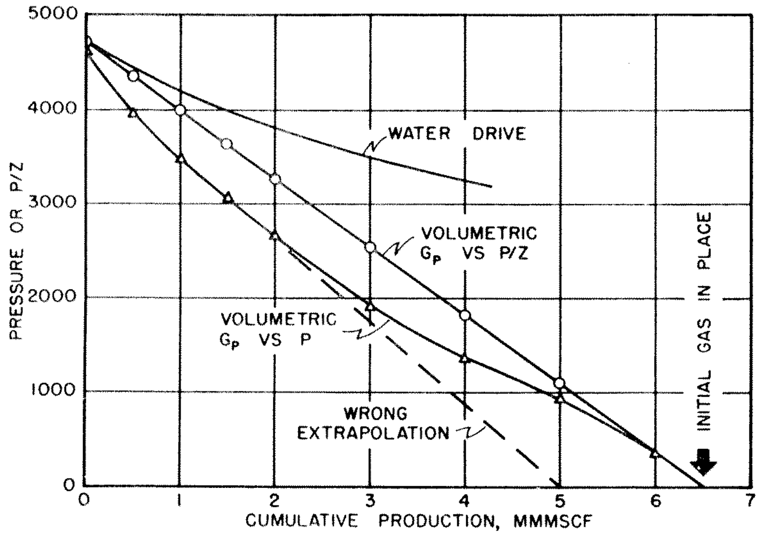

Fig. 1.9. Comparison of theoretical values of p and p/z plotted versus cumulative production from a volumetric gas reservoir.

$$m = \frac{\Delta G_p}{\Delta(p/z)} = \frac{6.5 \times 10^9}{4700} = 1.383 \times 10^6 \text{ SCF/psi}$$

Then for p_{sc} = 14.7 psia, T_{sc} = 520°R, and T = 200°F,

$$V_i = \frac{mp_{sc}T}{T_{sc}} = \frac{1.383 \times 10^6 \times 14.7 \times 660}{520}$$
$$= 25.8\text{MM cu ft}$$

For B_{gi} = 251.9 SCF/cu ft, the initial gas in place is

$$G = V_i \times B_{gi} = 25.8 \times 10^6 \times 251.9 = 6.50\text{MMM SCF}$$

Figure 1.9 also contains a plot of cumulative gas production G_p versus pressure. As indicated by Eq. (1.31) this is not linear, and extrapolations from the pressure-production data may be in considerable error. As the minimum value of the gas deviation factor occurs near 2500 psia, the extrapolations will be low for pressures above 2500 psia, and high for pressures below 2500 psia. Equation (1.30) may be used graphically as shown in Fig. 1.9 to find the initial gas in place or the reserves at any pressure for any selected abandonment pressure. For example at 1000 psia (or p/z = 1220) abandonment pressure the *initial* reserve is 4.85MMM SCF. At 2500 psia (or p/z = 3130) the (remaining) reserve is 4.85 less 2.20, that is 2.65MMM SCF. The equation may be used numerically as illustrated using data from the Bell Gas Field in Example 1.6. Note that the base pressure is 15.025 psia in the calculations of Example 1.6.

Example 1.6. Calculating the initial gas in place and the initial reserve of a gas reservoir from pressure-production data for a volumetric reservoir.

Given:

Initial pressure = 3250 psia
Reservoir temperature = 213°F
Standard pressure = 15.025 psia
Standard temperature = 60°F
Cumulative production = 1.00×10^9 SCF
Average reservoir pressure = 2864 psia
Gas deviation factor at 3250 psia = 0.910
Gas deviation factor at 2864 psia = 0.888
Gas deviation factor at 500 psia = 0.951

SOLUTION: Solve Eq. (1.30) for the reservoir gas pore volume V_i

$$\frac{15.025 \times 1.00 \times 10^9}{520} = \frac{3250 \times V_i}{0.910 \times 673} - \frac{2864\ V_i}{0.888 \times 673}$$

$$V_i = 56.17\text{MM cu ft}$$

The initial gas in place by Eq. (1.5) is

$$G = \frac{p_i V_i}{z_i T} \times \frac{T_{sc}}{p_{sc}} = \frac{3250 \times 56.17 \times 10^6 \times 520}{0.910 \times 673 \times 15.025}$$
$$= 10.32\text{MMM SCF}$$

The gas remaining at 500 psia abandonment pressure is

$$G_a = \frac{p_a V_i}{z_a T} \times \frac{T_{sc}}{p_{sc}} = \frac{500 \times 56.17 \times 10^6 \times 520}{0.951 \times 673 \times 15.025}$$
$$= 1.52\text{MMM SCF}$$

The initial gas reserve based on a 500 psia abandonment pressure is the difference between the initial gas in place and the gas remaining at 500 psia or

$$G_r = G - G_a = (10.32 - 1.52) \times 10^9$$
$$= 8.80\text{MMM SCF}$$

Equation (1.29) may be written in terms of gas volume factors B_{gi} and B_{gf} by solving it for G_p as

$$G_p = \frac{p_i T_{sc}}{p_{sc} z_i T} V_i - \frac{p_f T_{sc}}{p_{sc} z_f T} (V_i - W_e + B_w W_p)$$

But

$$B_{gi} = \frac{p_i T_{sc}}{p_{sc} z_i T}, \quad \text{SCF/cu ft}$$

$$B_{gf} = \frac{p_f T_{sc}}{p_{sc} z_f T}, \quad \text{SCF/cu ft}$$

Then

$$G_p = B_{gi} V_i - B_{gf}(V_i - W_e + B_w W_p)$$

V_i may be replaced by its equivalent G/B_{gi} so the equation becomes

$$G_p = G - B_{gf}\left(\frac{G}{B_{gi}} - W_e + B_w W_p\right)$$

Dividing through by B_{gf} and expanding

$$\frac{G_p}{B_{gf}} = G\left(\frac{1}{B_{gf}} - \frac{1}{B_{gi}}\right) + W_e - B_w W_p \tag{1.32}$$

If the gas volume factors are expressed in units of cubic feet per standard cubic foot instead of standard cubic feet per cubic foot, they will be in the numerator, and the equation reduces to the simpler form,

$$G_p B_{gf} = G(B_{gf} - B_{gi}) + W_e - B_w W_p \tag{1.33}$$

It is recalled that the gas volume factor is commonly expressed in four sets of units as given by Eq. (1.7). Equations containing the gas volume factor must therefore be checked carefully to see that the proper units are used. Also in Eq. (1.33) G and G_p must be expressed at the same base temperature and pressure as the gas volume factors. $G_p B_{gf}$ is the volume of the produced gas at the pressure p_f; $G(B_{gf} - B_{gi})$ is the change in volume of the initial gas when expanded from p_i to p_f; and W_e and $B_w W_p$ are the volumes of water influx and production respectively. Equation (1.33) may be expressed in conceptual form as

$$[\text{Production}] = [\text{Expansion}] + [\text{Water influx}] - [\text{Water production}]$$

For a volumetric reservoir the production volume equals the expansion volume and Eq. (1.33) becomes

$$G_p B_{gf} = G(B_{gf} - B_{gi}) \tag{1.34}$$

Equation (1.29) or its equivalent Eq. (1.33) is used in water-drive gas reservoirs to calculate the initial gas in place if the water influx is known, or the water influx when the initial gas in place is known from good log and core data. The problems of water influx will be discussed in detail in Chapter 5 where it will be shown in some cases it is possible to calculate the initial gas in place and the water influx from a set of simultaneous equations, Eqs. (1.29) or (1.33). Example 1.7 illustrates the use of the equations to

Example 1.7. Calculating water influx and residual gas saturation in water-drive gas reservoirs.

Given:

Bulk reservoir volume, initial = 415.3MM cu ft
Average porosity = 0.172
Average connate water = 0.25
Initial pressure = 3200 psia
B_{gi} = 0.005262 cu ft/SCF, 14.7 psia and 60°F
Final pressure = 2925 psia
B_{gf} = 0.005700 cu ft/SCF, 14.7 psia and 60°F
Cumulative water production = 15,200 bbl (surface)
B_w = 1.03 bbl/surface bbl
G_p = 935.4MM SCF at 14.7 psia and 60°F
Bulk volume invaded by water at 2925 psia = 13.04MM cu ft

SOLUTION:

$$\text{Initial gas in place} = G = \frac{415.3 \times 10^6 \times 0.172 \times (1 - 0.25)}{0.005262}$$
$$= 10{,}180\text{MM SCF at 14.7 psia and 60°F}$$

Substitute in Eq. (1.33) to find W_e,

$$W_e = 935.4 \times 10^6 \times 0.005700 - 10{,}180 \times 10^6 \; (0.005700 - 0.005262) + 15{,}200 \times 1.03 \times 5.615$$
$$= 960{,}400 \text{ cu ft}$$

This much water has invaded 13.04MM cu ft of bulk rock, which initially contained

25 per cent connate water. Then the final water saturation of the flooded portion of the reservoir is

$$S_w = \frac{\text{Connate water} + \text{Water influx}}{\text{Pore space}}$$

$$= \frac{(13.04 \times 10^6 \times 0.172 \times 0.25) + 960{,}400}{13.04 \times 10^6 \times 0.172}$$

$$= 0.68 \text{ or } 68 \text{ per cent}$$

Then the residual gas saturation S_{gr} is 32 per cent.

calculate the water influx when the initial gas in place is known. It also shows the method of estimating the residual gas saturation of the portion of the reservoir which has been invaded by water, where a reliable estimate of the invaded volume can be made. This is calculated from the isopachous map, the invaded volume being dilineated by those wells which have "gone to water production." The residual gas saturation calculated in Example 1.7 includes that portion of the lower permeability rock within the invaded area which actually may not have been invaded at all, the wells having been "drowned" by water production from the more permeable beds of the formation. Nevertheless it is still interpreted as the *average* residual gas saturation, which may be applied to the uninvaded portion of the reservoir.

In water-drive reservoirs the relation between G_p and p/z is, of course, not linear, as can be seen by an inspection of Eq. (1.29). Because of the water influx, the pressure drops less rapidly with production than under volumetric control, as shown in the upper curve of Fig. 1.9. Consequently, the extrapolation technique described for volumetric reservoirs is not applicable. Also, where there is water influx, the initial gas in place calculated at successive stages of depletion, *assuming no water influx*, takes on successively higher values; whereas with volumetric reservoirs the calculated values of the initial gas should remain substantially constant.

14. The Gas Equivalent of Produced Condensate and Water.

In the study of gas reservoirs in the preceding section it was implicitly assumed that the fluid in the reservoir at all pressures as well as on the surface was in a *single* (gas) phase. Most gas reservoirs, however, produce some hydrocarbon liquid, commonly called condensate, in the range of a few to a hundred or more barrels per million standard cubic feet. So long as the *reservoir* fluid remains in a single (gas) phase, the calculations of the previous sections may be used, provided the cumulative gas production G_p is modified to include the condensate liquid production. On the other hand, if a hydrocarbon liquid phase develops in the reservoir, the methods of the previous sections are not applicable, and these *retrograde*, gas-condensate reservoirs must be treated specially, as described in Chapter 2.

The reservoir gas production G_p used in the previous section must include the separator gas production, the stock tank gas production, and the stock tank liquid production converted to its *gas equivalent*, symbol GE. The stock tank gas production is the gas in solution in the separator liquid. It can be estimated from the bubble-point correlation for oil systems[40], the separator pressure being the bubble point of the liquid. The volume of solution gas may also be measured. The produced hydrocarbon liquid is converted to its gas equivalent assuming it behaves as an ideal gas when vaporized in the produced gas. Taking 14.7 psia and 60°F as standard conditions, the gas equivalent of one stock tank barrel of condensate liquid is

$$\text{GE} = V = \frac{nRT_{sc}}{p_{sc}} = \frac{350.5 \times \gamma_o}{M_o} \times \frac{10.73 \times 520}{14.7}$$

$$= 133{,}000\,\gamma_o/M_o \text{ SCF/STB}$$

The gas equivalent of one barrel of condensate of specific gravity 0.780 (water = 1.00) and molecular weight 138 is 752 SCF. The specific gravity may be calculated from the API gravity. If the molecular weight of the condensate is not measured, as by the freezing point depression method, it may be estimated using Eq. (2.3). Table 1.9 gives the gas equivalent of stock tank condensate liquids in the range of 45 to 65° API. If the analysis of the separator liquid is available, a more precise determination of its gas equivalent can be made. In this case the dissolved separator gas is included. Example 1.8 shows the calculation of the gas equivalent of the separator liquid and its dissolved gas to find the total reservoir production.

Table 1.9. GAS EQUIVALENT OF STOCK TANK CONDENSATE
$\text{GE} = 133{,}000\ \gamma_o/M_o$

Oil Gravity °API	Oil Specific Gravity = γ_o	*Molecular Weight = M_o	Gas Equivalent of Stock Tank Oil, SCF/STB
45	0.802	156	684
50	0.780	138	752
55	0.759	124	814
60	0.739	113	870
65	0.720	103	930

*Based on Eq. (2.3).

Example 1.8. Calculating the total daily gas production including the gas equivalents of water and condensate.

Given:

Daily separator gas production = 3.25MM SCF
Daily stock tank condensate = 53.2 STB

Daily stock tank gas = 10M SCF
Daily fresh water production = 5.5 bbl
Initial reservoir pressure = 4000 psia
Current reservoir pressure = 1500 psia
Reservoir temperature = 220°F
Condensate gravity = 55° API (0.759 sp. gr.)

SOLUTION: The estimated molecular weight of the condensate from Table 1.9 or by Eq. (2.3) is 124. Then the gas equivalent of the condensate is

$$\mathrm{GE} = 53.2 \times 133{,}000 \times \frac{0.759}{124} = 43{,}000 \text{ SCF}$$

The data of McCarthy, Boyd, and Reid[41] give a water content of 1.00 bbl/MM SCF at 4000 psia and 220°F and approximately 2.00 bbl/MM SCF at 1500 psia and 220°F. Then of the 5.5 bbl, only 3.25 bbl, i.e., 3.25MM × 1.00 bbl/MM, should be converted to gas, the remainder considered as produced water, and

$$\mathrm{GE_w} = 3.25 \times 7390 = 24{,}000 \text{ SCF}$$

Then the daily gas production ΔG_p is

$$\Delta G_p = 3250.0\text{M} + 10.0\text{M} + 43.0\text{M} + 24.0\text{M}$$
$$= 3.327\text{MM SCF}$$

Where water is produced on the surface as a condensate from the gas phase in the reservoir, it will be fresh water and it should be converted to a gas equivalent and added to the gas production. Since the specific gravity of water is 1.00 and its molecular weight is 18, its gas equivalent is

$$\mathrm{GE_w} = \frac{nRT_{sc}}{p_{sc}} = \frac{350.5 \times 1.00}{18} \times \frac{10.73 \times 520}{14.7}$$
$$= 7390 \text{ SCF/surface barrel}$$

Studies by McCarthy, Boyd, and Reid[41] indicate that the water vapor content of reservoir gases at usual reservoir temperatures and usual *initial* reservoir pressures is in the range of a fraction to one barrel per million standard cubic feet of gas. Production data from a Gulf Coast gas reservoir show a production of 0.64 barrel of water per million standard cubic feet compared with a reservoir *content* of about 1.00 bbl/MM SCF using the data of McCarthy, Boyd, and Reid. The difference is presumably that water remaining in the vapor state at separator temperature and pressure, most of which must be removed by dehydration to a level of about six *pounds* per million standard cubic feet. As reservoir pressure declines the water content will increase to as much as three barrels per million standard cubic feet. Since this additional content has come from vaporization of the connate water, it would appear that any *fresh* water produced in excess of the *initial* content should be treated as produced water and taken care of in the W_p term rather than the G_p term. Of course where the water is saline, it definitely is produced water; however, it includes the fraction of a barrel per million cubic feet obtained from the gas phase. If the produced gas is based on the dehydrated gas volume, the gas volume should be increased by the gas equivalent of the water content at the *initial* reservoir pressure and temperature regardless of the subsequent decline in reservoir pressure, and the water production should be diminished by the water content. This amounts to about a one-half per cent increase in the produced gas volumes.

15. Limitations of Equations and Errors. The precision of the reserve calculations by the volumetric method, Eq. (1.13), depends upon the accuracy of the data which enter the computations. The precision of the initial gas in place depends upon the probable errors in the averages of the porosity, connate water, pressure, and gas deviation factor, and in the error in the determination of the bulk productive volume. With the best of core and log data in rather uniform reservoirs, it appears doubtful that the initial gas in place can be calculated more accurately than about 5 per cent, and the figure will range upward to 100 per cent or higher depending upon the uniformity of the reservoir and the quantity and quality of the data available.

The reserve is the product of the gas in place and the recovery factor. For volumetric reservoirs the reserve of the reservoir as a whole, for any selected abandonment pressure, should be known to about the same precision as the initial gas in place. Water-drive reservoirs require, in addition, the estimate of the volume of the reservoir invaded at abandonment and the average residual gas saturation. When the reservoir exhibits permeability stratification, the difficulties are increased, and the accuracy is therefore reduced. In general, reserve calculations will be more accurate for volumetric than for water-drive reservoirs. Where the reserves are placed on a well or lease basis, the accuracy may be reduced further because of lease drainage, which occurs in both volumetric and water-drive reservoirs.

The use of the material-balance Eq. (1.33) to calculate gas in place involves the terms of the gas volume factor as expressed by Eq. (1.7). The precision of the calculations is, of course, a function of the probable error in these terms. The error in gas production G_p arises from error in gas metering, in the estimate of lease use and leakage, and in the estimate of the low pressure separator or stock tank gases. Sometimes underground leakage occurs as from the failure in casing cementing, or from casing corrosion; or in the case of dual completions, leakage between the two zones. Where gas is commingled from two reservoirs at the surface prior to metering, the division of the total between the two reservoirs depends on periodic well tests, which may introduce additional inaccuracies. Meters are usually calibrated to an accuracy of one per cent, and therefore it appears doubtful that the gas production under the best of circumstances is known closer than two per cent, and average accuracies are in the range of a few to several per cent.

Pressure errors are due to gauge errors and the difficulties in averaging, particularly where there are large pressure differences throughout the reservoir. When reservoir pressures are estimated from measured wellhead pressures, the errors of this technique enter the calculations. When the field is not fully developed, the average pressure is, of course, of the developed portion, which is lower than the reservoir as a whole. Water production with gas wells is frequently unreported where the amount is small, and where it is appreciable it is often estimated from periodic well tests.

In addition to the errors in the data which appear in the material-balance equation, there are some minor factors which have been neglected in the derivation of the equation: the change in volume of the connate water with pressure, the change in porosity with pressure, and the evolution of gas dissolved in the connate water with decrease in pressure. These factors may be included in the material balance where warranted by the precision of the data. The occurrence of small but unaccounted for amounts of water influx and/or retrograde condensation will affect the results. Under the best of circumstances, the material-balance estimates of the gas in place are seldom more accurate than five per cent, and may range much higher. The estimate of reserves is, of course, one step removed.

PROBLEMS

1.1. (a) From the list of elements in Table 1.4, find the molecular weights of the first six members of the paraffin hydrocarbon series: methane CH_4, ethane C_2H_6, propane C_3H_8, butane C_4H_{10}, pentane C_5H_{12} and hexane C_6H_{14}.
(b) What is the molecular weight of acetylene whose formula is C_2H_2?

1.2. The following experimental data were taken in determining the gas constant. An evacuated glass flask weighs 50.000 g. Filled with pure nitrogen at 14.40 psia and 60°F, it weighs 51.160 g. Filled with distilled water at 60° F, it weighs 1050.000 g. Calculate the gas constant from these data. *Ans:* 10.73.

1.3. Calculate the volume one pound mole of ideal gas will occupy at (a) 14.7 psia and 60°F, (b) 14.7 psia and 32°F, (c) 14.7 psia plus 10 oz and 80°F, and (d) 15.025 psia and 60°F. *Ans:* 379.4, 359.0, 377.9, 371.2.

1.4. A 1000 cubic-foot tank is filled with air to a pressure of 25 psia at 140°F. Calculate and place in tabular form for comparison, the molecular weight, specific gravity, pound moles in the tank, pounds in the tank, molecules in the tank, SCF at 14.7 psia and 60°F, SCF at 14.7 psia and 32°F, SCF at 14.7 psia + 10 oz and 80°F, and SCF at 15.025 psia and 60°F, for air, carbon dioxide, methane, and propane.

1.5. (a) State four ways in which a quantity of a pure gas may be specified.
(b) In what three ways may one mole of pure gas be defined?

1.6. A 500 cubic-foot tank contains 10 lb of methane and 20 lb of ethane at 90°F.
(a) How many moles are in the tank? *Ans:* 1.292.
(b) What is the pressure of the tank in psia? psig? *Ans:* 15.25, 0.55 for 14.7 psia atmospheric pressure.
(c) What is the molecular weight of the mixture? *Ans:* 23.22.
(d) What is the specific gravity of the mixture? *Ans:* 0.793.

1.7. Calculate the molecular weight of air if it contains 78.06 per cent nitrogen, 21.00 per cent oxygen, and 0.94 per cent argon by volume.
Suggestion: Calculate on the basis of one mole of air. Note that for gases mole per cent equals volume per cent. *Ans:* 28.97.

1.8. What are the molecular weight and specific gravity of a gas which contains one third each of methane, ethane, and propane by volume? *Ans:* 30, 1.034.

1.9. A ten-pound block of Dry Ice (solid CO_2) is placed in a 50 cubic-foot tank which contains air at atmospheric pressure 14.7 psia and 75°F. What will be the final pressure of the sealed tank when all the Dry Ice has evaporated and cooled the gas to 45°F? *Ans:* 38.47 psia.

1.10. A welding apparatus for a drilling rig uses acetylene (C_2H_2) which is purchased in steel cylinders containing 20 lb of gas, and costing $4.50 exclusive of the cylinder. If a welder is using 200 cu ft per day measured at 16 oz gauge and 85°F, what is the daily cost for acetylene? What is the cost per M CF at 14.7 psia and 60°F? *Ans:* $3.14, $15.40.

1.11. (a) A 55,000 bbl (nominal) pipe line tank has a diameter of 110 ft and a height of 35 ft. It contains 25 ft of oil at the time suction is taken on the oil with pumps which handle 20,000 bbl per day. The breather and safety valves have become clogged so that a vacuum is drawn on the tank. If the roof is rated to withstand $\frac{3}{4}$ oz per sq in. pressure, how long will it be before the roof collapses? Barometric pressure is 29.1 inches. Neglect the fact that the roof is peaked and that there may be some leaks.
Suggestion: Calculate the initial volume of air in the tank and the volume at collapse pressure. The difference between these two volumes is used to calculate the collapse time. Since they are large numbers and are very close to each other, the slide rule figures may give a difference which is greatly in error. *Ans:* 3.9 min.
(b) Calculate the total force on the roof at the time of collapse. *Ans:* 64,147 lb.
(c) If the tank had contained more oil, would the collapse time have been greater or less? Explain.

1.12. What is the molecular weight of a gas which contains 50 per cent C_1, 30 per cent C_2, and 20 per cent C_3 by *weight?*
Suggestion: Calculate on the basis of 100 lb of mixture. *Ans:* 21.83.

1.13. What volume will 100 lb of a gas of 0.75 specific gravity (air = 1.000) occupy at 100°F and 100 psia? *Ans:* 276 cu ft.

1.14. A 10 cubic-foot tank contains ethane at 25 psia surrounding a balloon 2 ft in diameter filled with methane at 35 psia. Neglecting the volume of the rubber in the balloon and assuming isothermal conditions, calculate the final pressure when the balloon is burst. *Ans:* 29.19 psia.

1.15. (a) What per cent methane by weight does a gas of 0.65 specific gravity contain which is composed only of methane and ethane? What per cent by volume? *Ans:* 67.8 per cent, 79.6 per cent.
(b) Explain why the per cent by volume is greater than the per cent by weight.

1.16. (a) A 1500 cubic-foot tank contains methane at 36 psia and 80°F. To it are added: 1.80 moles of ethane at 14.4 psia and 60°F, 25 lb of butane at 75°F, 4.65×10^{26} molecules of propane at 30°F, and 500 SCF (14.7 psia and 60°F) of nitrogen. If the final temperature of the mixture is 60°F, what is the final pressure of the tank? *Ans:* 48.43 psia.
(b) Of what significance are the temperatures given in part (a), with the moles of ethane, the pounds of butane, and the molecules of propane? Explain.

1.17. A 50 cubic-foot tank contains gas at 50 psia and 50°F. It is connected to another tank which contains gas at 25 psia and 50°F. When the valve between the two is opened, the pressure equalizes at 35 psia at 50°F. What is the volume of the other tank? *Ans:* 75 cu ft.

1.18. What is the weight of one molecule of pentane? *Ans:* 26.3×10^{-26}.

1.19. Gas was contracted at 5.5 cents per M CF at contract conditions of 14.4 psia and 80°F. What is the equivalent price at a legal temperature of 60°F and pressure of 15.025 psia? *Ans:* 5.96 cents.

1.20. What is the approximate weight, in tons, of one MM CF of natural gas? *Ans:* 25 tons for 0.65 specific gravity.

1.21. A cylinder is fitted with a leak-proof piston and calibrated so that the volume within the cylinder can be read from a scale for any position of the piston. The cylinder is immersed in a constant temperature bath, maintained at 160°F, which is the reservoir temperature of the Sabine Gas Field. Forty-five thousand cu cm of the gas, measured at 14.7 psia and 60°F, is charged into the cylinder. The volume is decreased in the steps indicated below, and the corresponding pressures are read with a dead weight tester after temperature equilibrium is reached.

V, cu cm —	2529	964	453	265	180	156.5	142.2
p, psia —	300	750	1500	2500	4000	5000	6000

(a) Calculate and place in tabular form the ideal volumes for the 45,000 cu cm, at 160°F at each pressure, and the gas deviation factors.

(b) Calculate the gas volume factors at each pressure, in units of cubic feet of reservoir space per standard cubic foot of gas and also in units of standard cubic feet per cubic foot of reservoir space.
(c) Plot the deviation factor and the gas volume factors calculated in part (b) versus pressure on the same graph.
(d) Express the gas volume factor at 2500 psia and 160°F in units of cu ft/SCF, SCF/cu ft, bbl/SCF, and SCF/bbl. *Ans:* 0.00590, 169.5, 0.00105, 952.

1.22. (a) If the Sabine Field gas gravity is 0.65, calculate the deviation factors from zero to 6000 psia at 160°F, in 1000-pound increments, using the gas gravity correlation of Fig. 1.2.
(b) Using the critical pressures and temperatures in Table 1.5, calculate and plot the deviation factors for the Sabine gas at several pressures and 160°F. The gas analysis is as follows:

Component	C_1	C_2	C_3	iC_4	nC_4	iC_5	nC_5
Mole Fraction	0.875	0.083	0.021	0.006	0.008	0.003	0.002
Component	C_6	$C^+{}_7$					
Mole Fraction	0.001	0.001					

Use the molecular weight and critical temperature and pressure of octane for the heptanes-plus. Plot the data of Prob. 21(a) and Prob. 22(a) on the same graph for comparison.
(c) Below what pressure at 160°F may the ideal gas law be used for the gas of the Sabine Field if errors are to be kept within two per cent? *Ans:* 180 psia.
(d) Will a reservoir contain more SCF of a real or of an ideal gas at similar conditions? Explain.

1.23. A high-pressure cell has a volume of 0.330 cu ft and contains gas at 2500 psia and 130°F, at which conditions its deviation factor is 0.75. When 43.6 SCF measured at 14.7 psia and 60°F are bled from the cell through a wet test meter, the pressure dropped to 1000 psia, the temperature remaining at 130°F. What is the gas deviation factor at 1000 psia and 130°F? *Ans:* 0.885.

1.24. (a) Calculate the bulk volume of the gas cap of a reservoir whose areal extent is 940 acres, i.e., the area enclosed by the zero thickness contour. The areas enclosed by the 4, 8, 12, 16, and 20-ft isopach lines are 752, 526, 316, 142, and 57 acres, respectively. The greatest thickness within the 20-ft isopach line is 23 ft. *Ans:* 8959 ac-ft.
(b) Show that when the ratio of the areas enclosed by two successive contours is 0.50, the error introduced by using the trapezoidal formula is 2 per cent greater than the pyramidal formula.
(c) What error is introduced by using the trapezoidal formula instead of the pyramidal formula when the ratio of the areas is 0.333? *Ans:* 4.7 per cent.

1.25. A volumetric gas field has an initial pressure of 4200 psia, a porosity of 17.2 per cent, and connate water of 23 per cent. The gas volume factor at 4200 psia is 292 SCF/cu ft and at 750 psia is 54 SCF/cu ft.
(a) Calculate the initial *in-place* gas in standard cubic feet on a unit basis. *Ans:* 1.68MM SCF/ac-ft.

(b) Calculate the initial gas *reserve* in standard cubic feet on a unit basis, assuming an abandonment pressure of 750 psia. *Ans:* 1.37MM SCF/ac-ft.
(c) Explain why the calculated initial *reserve* depends upon the abandonment pressure selected.
(d) Calculate the initial reserve of a 640-acre unit whose average net productive formation thickness is 34 ft, assuming an abandonment pressure of 750 psia. *Ans:* 29.8MMM SCF.
(e) Calculate the recovery factor based on an abandonment pressure of 750 psia. *Ans:* 81.5 per cent.

1.26. The discovery well No. 1 and wells No. 2 and No. 4 produce gas in the 7500-ft reservoir of the Echo Lake Field, Fig. 1.10. Wells Nos. 3 and 7 were dry in the 7500-ft reservoir; however, together with their electric logs and the one from well No. 1, the fault which seals the northeast side of the reservoir was established. The logs of wells Nos. 1, 2, 4, 5, and 6 were used to construct the map of Fig. 1.10, to locate the gas-water contact and to determine the average net sand thickness. The reservoir had been producing for 18 months when well No. 6 was drilled at the gas-water contact. The *static wellhead* pressures of the producing wells showed virtually no decline during the 18 month period prior to drilling well No. 6, and averaged near 3400 psia. The following data were available from electric logs, core analysis, etc.

Average well depth = 7500 ft
Average static wellhead pressure = 3400 psia
Reservoir temperature = 175°F
Gas specific gravity = 0.700 (air = 1.00)
Average porosity = 27 per cent
Average connate water = 22 per cent
Standard conditions = 14.7 psia and 60°F
Bulk volume of productive reservoir rock at the time No. 6 was drilled = 22,500 ac-ft.

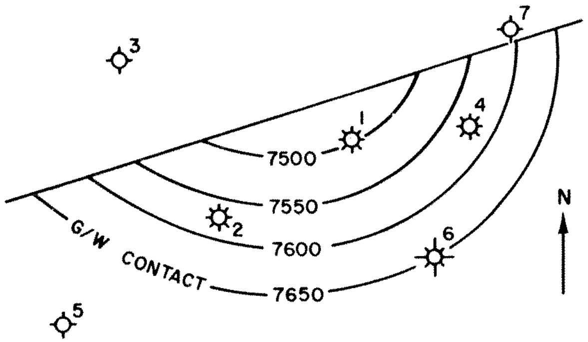

Fig. 1.10. Echo Lake Field, subsurface map, 7500 ft reservoir.

(a) Calculate the reservoir pressure using Eq. (1.12). *Ans:* 4038 psia.
(b) Estimate the gas deviation factor, and the gas volume factor in standard cubic feet per cubic foot. *Ans:* 0.90; 249.
(c) Calculate the reserve at the time well No. 6 was drilled assuming a residual gas saturation of 30 per cent. *Ans:* 33.8MMM SCF.
(d) Discuss the location of well No. 1 with regard to the over-all gas recovery.
(e) Discuss the effect of sand uniformity on over-all recovery, e.g., a uniformly permeable sand versus a sand in two beds of equal thickness, one of which has a permeability of 500 millidarcys, and the other, 100 millidarcys.

1.27. The "M" Sand is a small gas reservoir with an initial bottom-hole pressure of 3200 psia and bottom-hole temperature of 220°F. It is desired to inventory the gas in place at three production intervals. The pressure-production history and gas volume factors in cubic feet per standard cubic foot at standard conditions of 14.7 psia and 60°F are as follows:

Pressure psia	Cumulative Gas Production MM CF	Gas Volume Factor cu ft/SCF
3200	0	0.0052622
2925	79	0.0057004
2525	221	0.0065311
2125	452	0.0077360

(a) Calculate the initial gas in place using production data at the end of each of the production intervals, assuming volumetric behavior. *Ans:* 1028, 1138, and 1414MM SCF.
(b) Explain why the calculations of part (a) indicate a water drive.
(c) Show that a water drive exists by plotting the cumulative production versus p/z.
(d) Based on electric log and core data, volumetric calculations on the "M" Sand showed that the initial volume of gas in place is 1018MM SCF. If the sand is under a partial water drive, what is the volume of water encroached at the end of each of the periods? There was no appreciable water production. *Ans:* 756, 27,000, and 174,200 bbl.

1.28. When the Sabine Gas Field was brought in, it had a reservoir pressure of 1700 psia, and a temperature of 160°F. After 5.00MMM SCF (14.7 psia plus 4 oz and 80°F) was produced, the pressure had fallen to 1550 psia. If the reservoir is assumed to be under volumetric control, using the deviation factors of Prob. 21, calculate the following:
(a) The hydrocarbon pore volume of the reservoir. *Ans:* 433 × 10^6 cu ft.
(b) The pounds of gas initially in place if the gas gravity is 0.65. *Ans:* 2.43MMM lb.
(c) The SCF (14.7 psia and 60°F) of gas initially in place. *Ans:* 48.9MMM SCF.
(d) The SCF produced when the pressure falls to 1550, 1400, 1100, 500, and 200 psia. Plot cumulative recovery in SCF versus p/z. *Ans:* 4.9, 9.6, 18.7, 35.9, 43.9MMM SCF.

(e) From your graph find how much gas can be obtained without the use of compressors for delivery into a pipeline operating at 750 psia. *Ans:* 29.3MMM SCF.

(f) What is the approximate pressure drop per MMM SCF of production? *Ans:* 32 psi.

(g) Calculate the *minimum* value of the initial reserve if the produced gas measurement is accurate to ± 5 per cent and if the average pressures are accurate to ± 12 psi when 5.00MMM SCF (14.7 psia plus 4 oz and 80°F) have been produced and the reservoir pressure has dropped to 1550 psia. *Ans:* 24.8MMM SCF at 750 psia abandonment pressure.

1.29. *If*, however, during the production of 5.00MMM SCF of gas in the preceding problem, 4.00MM bbl of water had encroached into the reservoir and still the pressure had dropped to 1550 psia, calculate the initial in-place gas. Compare with Prob. 28 (c). *Ans:* 26.1MMM SCF.

1.30. (a) The gas cap of the St. John Oil Field had a bulk volume of 17,000 acre-feet when the reservoir pressure had declined to 634 psig. Core analysis shows an average porosity of 18 per cent, and an average interstitial water of 24 per cent. It is desired to increase the recovery of oil from the field by repressuring the gas cap to 1100 psig. Assuming that no additional gas dissolves in the oil during repressuring, calculate the SCF (14.7 psia and 60°F) required. The deviation factors for both the reservoir gas and the injected gas are 0.86 at 634 psig and 0.78 at 1100 psig, both at 130°F. *Ans:* 4.1MMM SCF.

(b) If the injected gas has a deviation factor 0.94 at 634 psig and 0.88 at 1100 psig, and the reservoir gas deviation factors are as above, recalculate the injected gas required. *Ans:* 3.6MMM SCF.

(c) Is the assumption that no additional solution gas enters the reservoir oil a valid one?

(d) Considering the possibility of some additional solution gas and the production of oil during the time of injection, will the figure of (a) be maximum or minimum? Explain.

(e) Explain why the gas deviation factors are higher (deviation less) for the injected gas in part (b) than for the reservoir gas.

1.31. (a) A well drilled into a gas cap for gas recycling purposes is found to be in an isolated fault block. After injecting 50MM SCF (14.7 psia and 60°F), the pressure increased from 2500 to 3500 psia. Deviation factors for the gas are 0.90 at 3500 and 0.80 at 2500 psia and the bottom-hole temperature is 160°F. What is the cubic feet of gas storage space in the fault block? *Ans:* 1.15MM cu ft.

(b) If the average porosity is 16 per cent, average connate water is 24 per cent, and average sand thickness is 12 feet, what is the areal extent of the fault block? *Ans:* 18 acres.

1.32. The initial volume of gas in place in the "P" Sand reservoir of the Holden Field is calculated from electric log and core data to be 200MMM SCF (14.7 psia and 60°F) underlying 2250 productive acres, at an initial pressure of 3500 psia and 140°F. The pressure-production history is

Pressure, psia	Production MMM SCF	Gas Deviation Factor at 140°F
3500 (initial)	0.0	0.85
2500	75.0	0.82

(a) What is the initial volume of gas in place as calculated from the pressure-production history assuming no water influx? *Ans:* 289MMM SCF.

(b) Assuming uniform sand thickness, porosity, and connate water, if the volume of gas in place from pressure-production data is believed to be correct, how many acres of extension to the present limits of the "P" Sand are predicted? *Ans:* 1000 acres.

(c) If, on the other hand, the gas in place calculated from the log and core data is believed to be correct, how much water influx must have occurred during the 75MMM SCF of production to make the two figures agree? *Ans:* 22.8MM bbl.

1.33. Explain why initial calculations of gas in place are likely to be in greater error during the early life of depletion type reservoirs. Will these factors make the predictions high or low? Explain.

1.34. A gas reservoir under partial water drive produced 12.0MMM SCF (14.7 psia and 60°F) when the average reservoir pressure had dropped from 3000 psia to 2200 psia. During the same interval an estimated 5.20MM bbl of water entered the reservoir based on the volume of the invaded area. If the gas deviation factor at 3000 psia and bottom-hole temperature of 170°F is 0.88 and at 2200 psia is 0.78, what is the initial volume of gas in place measured at 14.7 psia and 60°F? *Ans:* 42.9MMM SCF.

1.35. A gas-producing formation has a uniform thickness of 32 ft, a porosity of 19 per cent, and connate water saturation of 26 per cent. The gas deviation factor is 0.83 at the initial reservoir pressure of 4450 psia and reservoir temperature of 175°F. (S.C. 14.7 psia and 60°F)

(a) Calculate the initial in-place gas per acre-foot of bulk reservoir rock. *Ans:* 1.83MM SCF.

(b) How many years will it take a well to deplete by 50 per cent a 640-acre unit at the rate of 3MM SCF/day? *Ans:* 17.1 years.

(c) If the reservoir is under an active water drive so that the decline in reservoir pressure is negligible, and during the production of 50.4MMM SCF of gas, measured at 14.7 psia and 60°F, water invades 1280 acres, what is the per cent recovery by water drive? *Ans:* 67.24 per cent.

(d) What is the gas saturation as per cent of total pore space in the water invaded portion of the reservoir? *Ans:* 24.24 per cent.

1.36. Calculate the daily gas production including the condensate and water gas equivalents for a reservoir with the following daily production.

Separator gas production = 6MM SCF
Condensate production = 100 STB
Stock tank gas production = 21M SCF
Fresh water production = 10 bbl
Initial reservoir pressure = 6000 psia
Current reservoir pressure = 2000 psia
Reservoir temperature = 225°F
Water vapor content at 6000 psia and 225°F = 0.86 bbl/MM SCF
Condensate gravity = 50° API

Ans: 6.134MM SCF.

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2

Gas-Condensate Reservoirs

1. Introduction. Gas-condensate production may be thought of as a type intermediate between oil and gas. Oil reservoirs have a dissolved gas content in the range of zero (dead oil) to a few thousand cubic feet per barrel, whereas in gas reservoirs one barrel of liquid (condensate) is vaporized in 100,000 standard cubic feet of gas or more, and from which, therefore, a small or negligible amount of hydrocarbon liquid is obtained in surface separators. Gas-condensate production is predominately *gas* from which more or less liquid is *condensed* in the surface separators, hence the name gas-condensate. The liquid is sometimes called by an older name *distillate*, and also sometimes simply oil, since it is an oil. Gas-condensate reservoirs may be approximately defined as those which produce light-colored or colorless stock tank liquids with gravities above 45° API at gas-oil ratios in the range of 5000 to 100,000 SCF/bbl. Allen[*, 1] has pointed out the inadequacy of classifying wells and the reservoirs from which they produce entirely on the basis of surface gas-oil ratios; for the classification of reservoirs properly depends upon (a) the composition of the hydrocarbon accumulation and (b) the temperature and pressure of the accumulation in the earth. Reservoirs have been discovered which contain the various hydrocarbons, and sometimes some other compounds, in almost every conceivable set of proportions. Further, while temperatures and pressures increase with depth, because their rates of increase (gradients) vary considerably from area to area, a rather wide variety of pressure-temperature combinations is found in naturally occurring reservoirs. Because of these facts there are no distinct dividing lines between the types into which reservoirs may be divided. They blend into one another, and even overlap, sometimes causing technical and legal misunderstanding.

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[*] References throughout the text are given at the end of each chapter.